University of Stavanger

Faculty of Science and Technology

MASTER'S THESIS

Study program/ Specialization: Offshore Technology, Subsea Technology	Spring semester, 2012 ~~Open~~ / Restricted access
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Title of thesis: Design of Bore Selector for Tordis Vigdis Workover System	
Credits (ECTS): 30	
Key words: Bore Selector, Workover System, Open water riser, Tordis Vigdis, Wall Thickness, Pressure Design.	Pages: 66 + enclosure: 101 Stavanger, 14th June, 2012 Date/year

ABSTRACT

The cost of the workover system and the time required to run the workover equipment constitute a significant component in the subsea workover/intervention cost. But, the cost can be minimized by modifying traditional equipment configuration and design. Bore selector is one such concept, which helps to reduce the cost of the subsea workover system.

The concept of the bore selector is designed for shallow water depth and reservoir conditions of the Tordis Vigdis field. Currently the Tordis Vigdis workover system does not have a bore selector and both the production and annulus lines are accessed separately using dual bore workover riser. The novel steps in the development of a bore selector for this workover system are discussed in the thesis. During the design process, the study for the best location of bore selector in the workover system is investigated and found out. Subsequently, different concept has been developed, and the best one is selected for design based on evaluation criteria. 3D model of the selected bore selector is built with the help of the drawing tool ‘Creo Element/Pro’. The wall thickness of the selected model has been verified against API and ISO standards with the chosen yield and tensile strength values to with stand the internal and external pressure. Pressure design calculation is done for different operating conditions viz. normal, extreme and accidental with corresponding design factors to ensure that the design is within acceptable limits. The thesis, thus explains the preliminary design work for a bore selector in Tordis Vigdis workover system.

ACKNOWLEDGEMENT

This thesis is performed as part of the Master of Science degree in Offshore Technology at the University of Stavanger to fulfil the requirement for the final semester. The thesis work is carried out at the GE Oil & Gas, Dusavik facility in Stavanger.

First of all, I would like to thank Professor Eiliv Janssen who agreed to help me as faculty supervisor for this master thesis on bore selector. His guidance and suggestions were instrumental in each and every phase of the project, and I feel extremely lucky to do my thesis under such a proficient and knowledgeable professor.

I express my sincere gratitude towards my external supervisor Mr. Siby Abraham at GE Oil & Gas. He always spared time in his busy schedule to clarify my doubts and inject new thoughts and ideas. I am indebted to my colleagues in GE who always supported me with helping hands and was open to queries all time.

I would also like to take this opportunity to thank Statoil engineers at the Saga Fjord base for their assistance to take me around the base and show all the workover equipments used for the Tordis Vigdis field. Mr. Arild Magne Olset, Mr. Ottar Akselsen, and Mr. Sven Murray Heartness were kind to spend their time with me to explain and make me understand the workover system for the field.

Last but not the least my family back in India. Your love, prayers and support kept me motivated in every hardship. Also, my friends deserve special appreciation for the way they had motivated and taken care of me in finishing the tasks when I was running out of time.

Finally to God Almighty who makes all the plans and guide me in the right path.

DEFINITIONS

Annulus circulation line-The line(s) shall normally be used for C/WO riser circulation, tubing annulus circulation, tubing annulus pressurization and well kill.

Common well barrier element- This is a barrier element that is shared between primary and secondary barrier.

Completion – Activities and methods for preparing a well for the production of oil and gas.

Completion/workover activities – Equipment installation & retrieval, down hole wireline or coiled tubing operations to stimulate production or other.

Completion/workover riser : Temporary riser used for completion or workover operations and includes any equipment between the subsea tree/tubing hanger and the workover floaters tensioning system.

Corrosion allowance- The amount of wall thickness added to the pipe or component to allow for corrosion/erosion/wear.

Drilling riser- A riser utilised during drilling and workover operations and isolates any wellbore fluids from the environment.

Effective tension - The axial wall force (axial pipe wall stress times area) adjusted for the contributions from external and internal pressure.

Environmental loads- Loads due to the environment, such as waves, current, wind, ice and earthquake.

Functional loads- Loads caused by the physical existence of the riser system and by the operation and handling of the system, excluding pressure loads.

Global analysis : Analysis of the complete riser system.

Killing the well - displacement of fluids in the wellbore to counteract the downhole well pressure.

Primary well barrier – First object that prevents flow from a source.

Riser- The portion of a pipeline extending from the seafloor to the surface is termed a riser.

Secondary well barrier- Second object that prevents flow from a source.

Well intervention-Well maintenance without killing the well and performing full workover is time saving.

Well barrier - envelope of one or several dependent barrier elements preventing fluids or gases from flowing unintentionally from the formation, into another formation or to surface.

Well barrier element- An object that alone cannot prevent flow from one side to other side of itself.

Workover (recompletion) -Remedial operations on a producing well to increase production.

Workover riser - jointed riser that provides a conduit from the subsea tree upper connection to the surface and allows for the passage of tools during workover operations of limited duration, and can be retrieved in severe environmental conditions.

ABBREVIATIONS

API	American Petroleum Institute
BOP	Blow out Preventer
C/WO	Completion/Workover
CWJ	Cased Wear Joint
DNV	Det Norske Veritas
EDP	Emergency Disconnect Package
EQD	Emergency Quick Disconnect
ESD	Emergency Shut Down
FAT	Factory Acceptance Test
FPSO	Floating Production Storage and Offloading
FSA	Fail Safe As Is
GE	General Electric
HISC	Hydrogen Induced Stress Cracking
HXT	Horizontal Christmas Tree
ISO	International Organization for Standardization
LWRP	Lower Workover Riser Package
MODU	Mobile Offshore Drilling Unit
MWP	Maximum Working Pressure
NACE	National Association of Corrosion Engineers
NCS	Norwegian Continental Shelf
NORSOK	Norsk Sokkels Konkuranseposisjon
NPD	Norwegian Petroleum Directorate
PSA	Petroleum Safety Authority
PSD	Process Shut Down
PSL	Product Specification Level

ROV	Remotely Operated Vehicle
RDP	Riser Disconnect Package
RL	Rapid Lock
SCM	Subsea Control Module
SIT	Site Integration Test
SPS	Subsea Production Systems
STT	Surface Test Tree
T/V	Tordis/ Vigdis
TH	Tubing Hanger
TR	Technical Requirement
TRT	Tree Running Tool
TTA	Technical Target Areas
VXT	Vertical Christmas tree
WCP	Well Control Package
WO	Workover
WOCS	WorkOver Control System
XMT	Christmas Tree

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Overview of Figures and Tables

1 INTRODUCTION

The oil and gas production in the Norwegian Continental Shelf (NCS) has matured with the fields turning older and the output declining rapidly (Refer *Appendix A Figure 7-1* for the data from Norwegian Petroleum Directorate). In order to increase the production level in NCS the industry must look into exploring new fields, develop the neighbouring fields in ways that are compatible with the existing fields and processing equipment, while sustaining the production level from the mature fields. Maintaining the current production level from the existing fields is possible by optimizing the oil and gas recovery from the existing ageing fields. Intervention and work over plays a significant role in maintaining, restaining and improving productivity. These operations can bring profit to operators from otherwise a non economical well. Low cost and cost effective interventions are vital in performing ulimate oil recovery in a profitable manner. Apparently, the rig/vessel cost, the cost of the workover equipment, the time in running the workover equipments constitute the bulk of the expenses incurred during an intervention.

Completion/Work Over(C/WO) riser systems are used for the installation of the subsea trees, completion equipment and during major well work overs. These systems typically require the use of a mobile offshore drilling unit (MODU) equipped with full wellbore-diameter pressure control equipment. One of the major components in a workover system is a C/WO riser which is used to connect the surface support systems on a rig or vessel to the lower workover riser package (LWRP), which is latched onto the XMT re-entry hub.The cost and time required to run a dual bore Completion/WO riser has lead to the idea of developing a bore selector which helps in accessing a particular bore (either production or annulus) according to the type of workover operation planned. Access to a dual-bore riser can be complicated, potentially involving long delays and large capital investment; thus increasing operational costs. Hence the bore selector concept can be considered as a method of accessing either of two bores from a mono bore riser.

This thesis is intended to design a bore selector for the work over system which is used in the Tordis/Vigdis(T/V) field. It is written in collaboration with GE Oil & Gas; one of the leading oil and gas service providers. The customer always prefer a much lighter and easy to handle workover system for cost effective operations. Hence the design of the bore selector should finally match the customer requirements. This will help GE Oil & Gas to meet their challenges and competition in their aftermarket segment. Also, the bore selector design can be seen as an innovative concept for future fields in development.

1.1 BACKGROUND

The first subsea tree was installed in 1960's (Jossang S. N, et.al., 2008), and since then the subsea field development concept has gained popularity and is widely accepted in the oil and gas industry. The number of subsea wells has increased steadily over the years and is estimated to have exceeded 5500 by the end of 2010 (Skeie T, Hjorteland O. and Arnskov

M.M., 2011). The production figures for the year 2010 from Norwegian Petroleum Directorate (NPD) confirm the fact that oil and gas production from subsea wells in the norwegian continental shelf is now more than from the platform wells. (Refer *Appendix A Figure 7-2*). Almost 131.3 million standard cubic meters (Sm^3 o.e.) oil equivalents were produced from subsea wells and about 125.4 million Sm3 o.e. from platform wells (NPD, 2010). Albeit, the fact that the production is more from the subsea wells; the recovery rate from subsea wells in general is substantially low as compared to direct platform access wells. This is due to the complex well intervention and maintenance characteristics required for the subsea wells. Accessing a subsea well is considered more complicated and represents large cost compared to accessing other types of wells. Even minor jobs represent large expenses, leaving a gap between intervention frequency on subsea wells and the rest. The high intervention cost is mainly attributed to the daily rates of the rig required to carry out such operations when the traditional and conventional approach of intervention is adopted. Hence due to the lack of routine intervention the subsea wells perform at only 75% of comparable land and platform wells (Schlumberger, 2003). However, in Norwegian sector the emphasis has been on increased oil recovery from subsea wells to achieve a rise of recovery rate from approximately 43-45% to approximately 55% (Jossang S. N, et.al., 2008). Interestingly, a minor 1% increase in recovery of original oil in place will give way to an income of about 270bn NOKS (TTA3, 2011).

Subsea wells need to be intervened more often to achieve this target. Traditionally, some intervention is required every 4th year(or more often) in subsea wells (Munkerud P. K. and Inderberg O., 2007). A well may require intervention due to flow restrictions, changes in reservoir characteristics, sand production, mechanical failure, or to access additional hydrocarbon pay zones (Offshore magazine, 2002) . *Appendix A Figure 7-3* refers to relative intervention frequencies due to different services which includes, both platform and subsea wells. Downhole applications that are performed during well interventions include well surveillance and diagnostics, implementation of reservoir management techniques, completion repair and re entry drilling to reach new producing intervals (Khurana S., Dewalt B. and Headworth C., 2003). Using heavy and traditional rigs for subsea intervention is a costly and time consuming affair due to the high rental cost and lengthy mobilization/transit times. Also, the use of rig requires killing the well which creates the risk of damaging the reservoir. Hence rigless technology is being widely discussed in the industry as an alternate solution. This might include through-tubing tractor technology for both wireline and coiled tubing, new downhole water gas shutt off and zonal isolation tools and low cost intervention systems and vessels. Riserless lightweight intervention can be used for cost effective wireline work(like perform logging, to repair safety valves, to adjust the completion etc.) in subsea wells (TTA3, 2011).

However, a MODU has certain advantages, which makes them equally competetive in the market. Even though a conventional rig is not required for wireline, coiled tubing and hydraulic workover; a rig has the capability to handle the work over riser using the same equipment used for its drilling riser system. Other most important advantage for well intervention is their ability to change the work scope in the middle of ongoing job, to carry out heavy workover tasks, such as pulling the completion if the situation downhole proves to be different from what was expected when planning the intervention. This is common in subsea well intervention due to the remoteness of subsea wells and consequent lack of downhole information. Nevertheless, in intervention jobs like sand control mechanical failures, a recompletion has to be performed which can be done only with the help of a rig (Khurana S., Dewalt B. and Headworth C., 2003).

To perform these functions on subsea wells a vessel or rig, and sometimes a marine riser- a large tube that connects the subsea well to the surface is required. All this adds up to significant cost. In many cases, the subsea production tree must be removed. Reconnecting to many subsea wells, to perform workover and recompletions can also require a specially designed intervention system to control the well and allow other tools to pass through it down to the level of the reservoir (Schlumberger, 2003).

The cost of a rig depends on the complexity of the job undertaken(*Refer Figure 7-4*) and the time required to execute it. Major savings can be obtained if the time required to run the workover equipment (for example running the workover riser) is reduced. The workover risers are quite large in size and require bigger handling requirement and consume more space for storage. The dual bore workover risers being large in its size, the time required to make, connect and run the riser is also higher. A smaller and lighter riser equate directly to reduced riser tension, deck load requirements and less deck space, which allows smaller older MODU's to be used in deeper waters.

However, several recent technological development has helped in reducing cost by simplifying operational programs and equipment configurations, while adding to operational flexibility. One such mechanism is a '***Bore Selector***', which facilitate the elimination of the annulus line, thereby making the entire dual bore workover system to a monobore riser. *Figure 1-1* shows a generic bore selector mechanism.

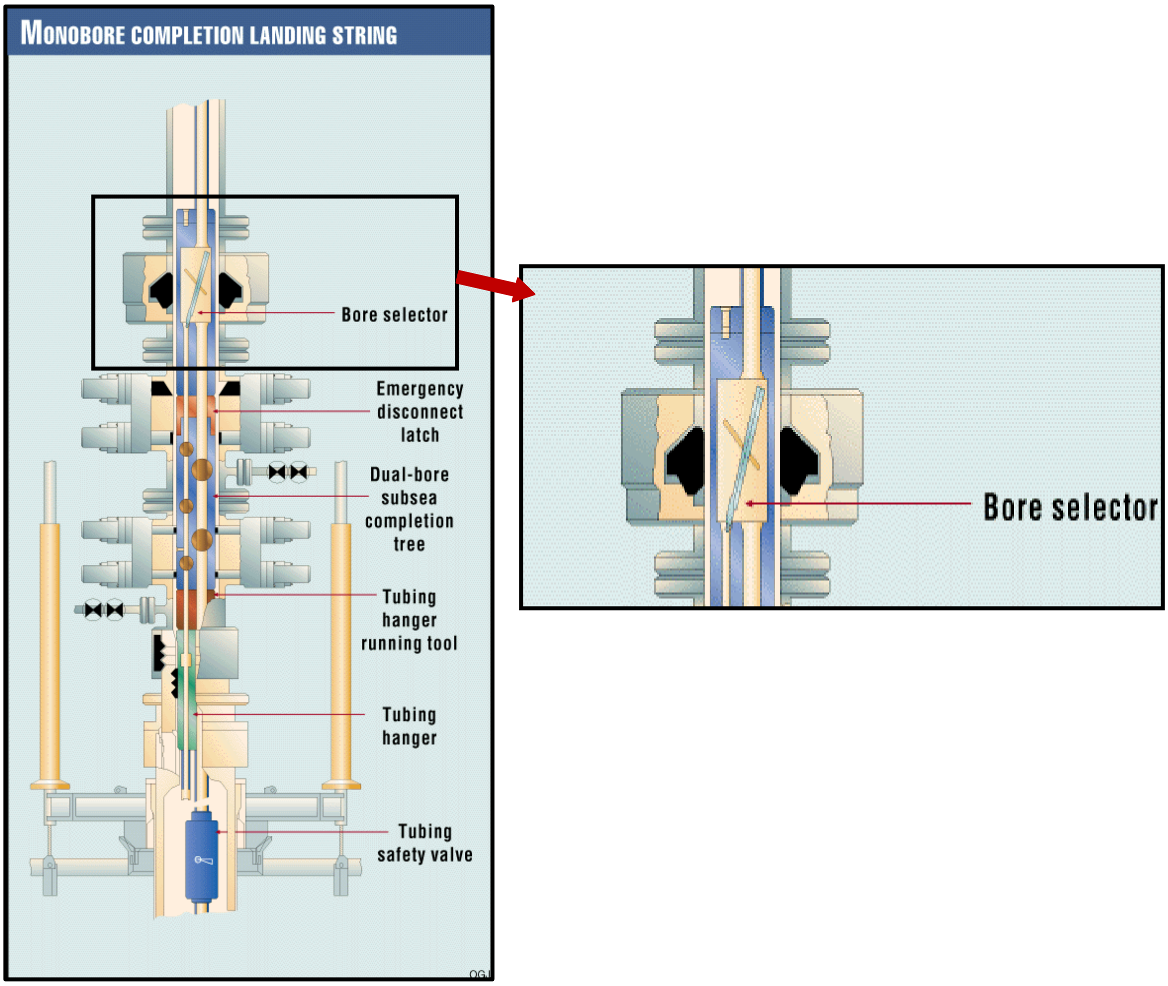


Figure 1-1 Generic bore selector in Tubing Hanger mode (Source Oil & Gas Journal)

1.2 OBJECTIVE OF THE THESIS

The objective of the master thesis is to propose a design of bore selector for the workover system used in Tordis Vigdis field. The design process primarily consists of the study of the existing workover system in the Tordis Vigdis field from different sources such as drawings, reports etc., recognition of the need for a bore selector including study of a bore selector which comprises of literature survey into various bore selectors designed and patented in the industry. The design requirements for the bore selector is specified after which the proposed conceptual models are presented in the form of figures. These different concepts are compared using the evaluation criteria and ranked. The highest ranked conceptual model is considered further for detailed design with supporting drawing and calculations. All the design will be adhering to the relevant API & ISO standards.

1.3 METHOD OF THE THESIS

The design process(as shown in *Figure 1-2*), starts with the understanding of the existing workover system of the T/V field. The discussion for the need of the bore selector will be followed by the available solutions in the industry along with the patents registered as bore selector. The design requirements and specifications with respect to Tordis Vigdis field are required in the next stage. The discussion on where to position the bore selector on this workover system is imperative before the conceptual design stage. The drawings of different bore selector will be presented in the conceptual design, and they will be evaluated on the basis of functional and operational criteria. Then the selected design is further drawn with dimensions in the preferred conceptual design of the concept. Wall thickness calculations, bending moment and tensile strength calculation is made on the basis of this design. The detailed design part should contain global riser analysis to find the limiting sea states for the operation. Also, detailed drawing and finite element analysis are done during this stage. With the help of detailed drawing, a prototype of the bore selector will be manufactured which has to undergo testing and qualification.

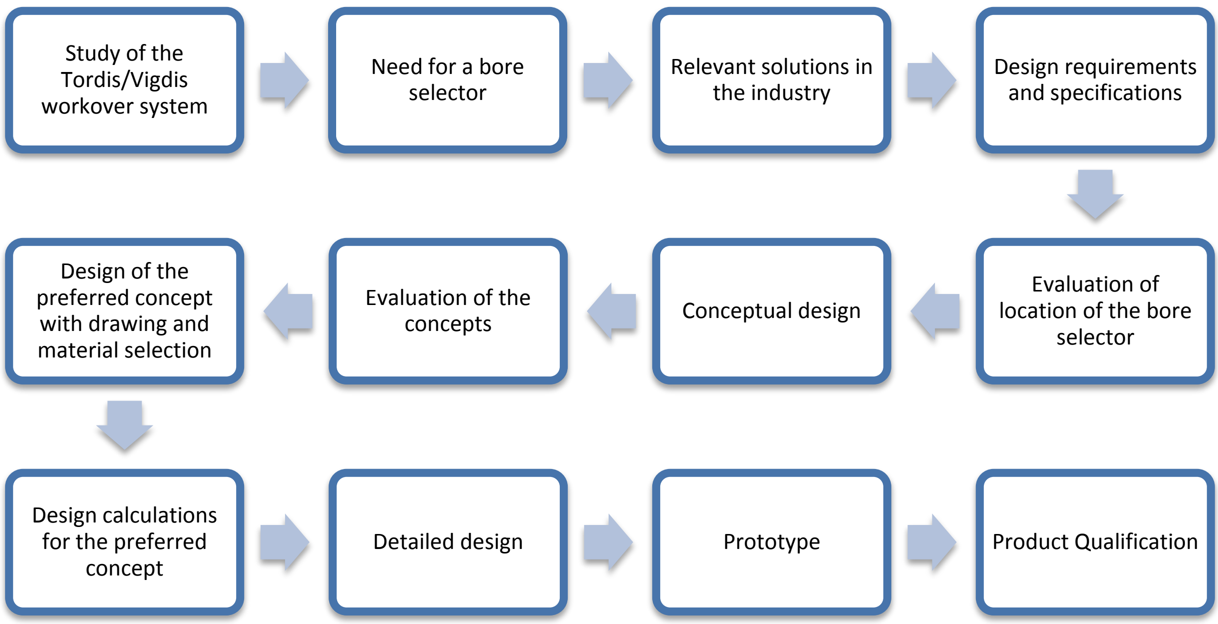


Figure 1-2 Design Flowchart

The design shall conform to the applicable industry standards and/or regulations set forth by governing bodies. Although most regulations will require compliance with accepted industry standards, there will be local regulations that need to be followed during the design procedure. For example, equipment designed for operation in the Norwegian sector of the North Sea should be designed to comply with the applicable regulations of the Norwegian Petroleum Directorate. Hence the equipment designs may still conform to any appropriate industry standards with an outlook into local regulations.

Specific design requirements imposed by customer also should be taken into consideration. However, if such customer requirements are in conflict with any appropriate industry standard or governing body regulation, the specifics of such conflict shall be clearly documented within engineering. Customer requirements(for example TR documents from Statoil) which are in addition to industry standards or governing body regulations are not considered to be in conflict with same. *Figure 1-3* below shows the hierarchy to be followed

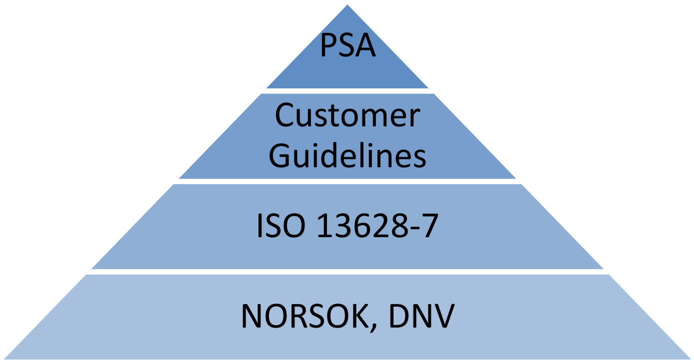


Figure 1-3 Requirements Hierarchy

2 THEORY

This part of the thesis gives an overview about the Tordis Vigdis Field, Subsea Production Systems, Well intervention, Workover and the different components in a workover system.

Tordis Vigdis Field

The Tordis and Vigdis field lies in block 34/7 in the Tampen area of the Norwegian North Sea and came onstream in 1994 and 1997 respectively. The field development concept is subsea installations tied back to platforms. The water depth is in the range of 200-280 m. In addition to the main Tordis structure, the development embraces Tordis East (1998), Borg (1999) and Tordis South East (2001) fields. For Vigdis field, in addition to the main structure the field comprises of the Borg North- West and Vigdis East structures. *Figure 2-1* shows the T/V field layout.

The well stream from Tordis is routed through two pipelines to the Gullfaks platform 10 kilometres away for processing, storage and export. Vigdis is tied back to Snorre A platform seven kilometres away for processing. Gas separated from the Vigdis is injected into the Snorre field, while gas from Borg North-West and Vigdis East is piped from Snorre A to Statfjord A. Stabilised oil is transported by pipeline to Gullfaks A for storage and export.

The former Saga petroleum company became operator for license PL089 when the license was awarded in 1984. Norsk Hydro took over the operatorship after acquiring Saga in 1999. Statoil took over operatorship on 1 January 2003.

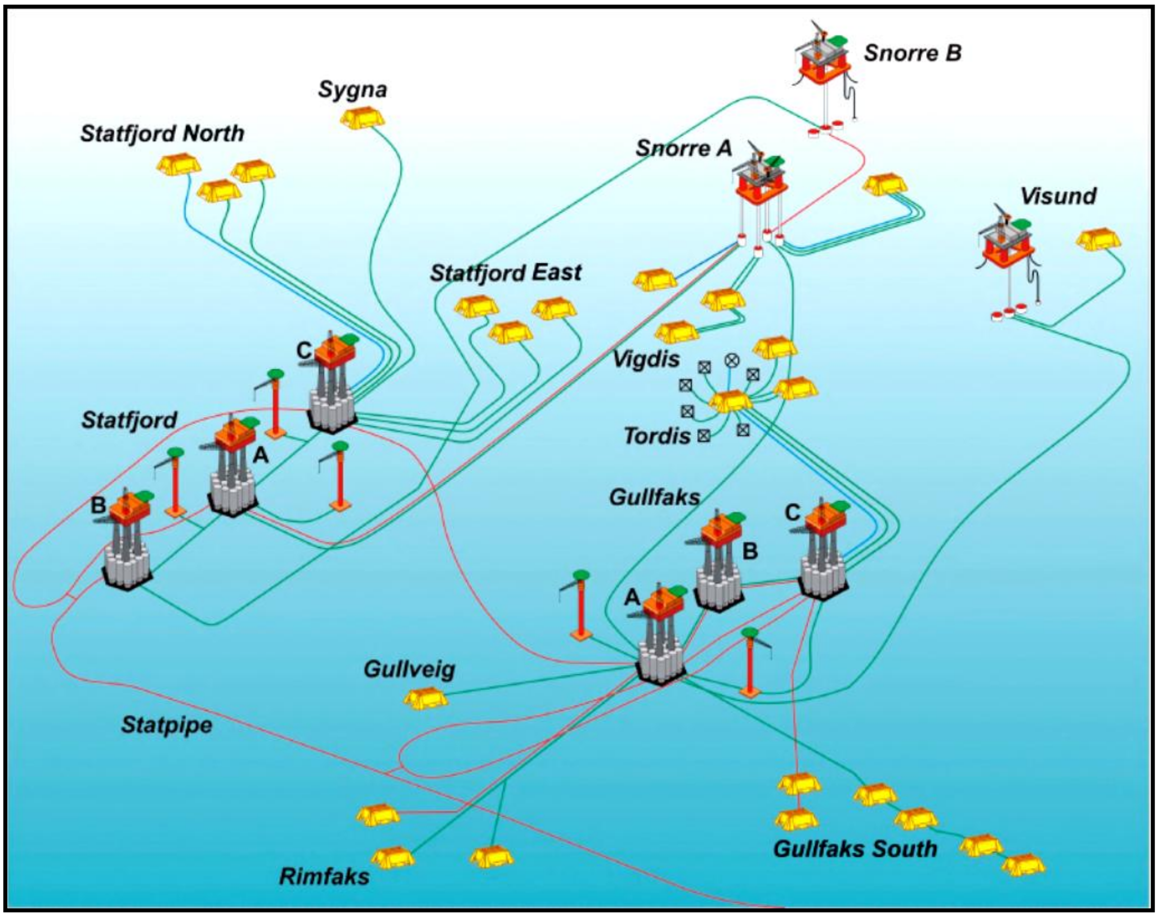


Figure 2-1 Tordis Vigdis Subsea Field Layout (Source Statoil)

Subsea Production System

SPS possess the capabilities to extract and control hydrocarbons from a reservoir and eventually route these fluids to a processing facility. All equipment necessary to perform this task are located in the subsea environment. A Subsea production system consists of a subsea completed well, seabed wellhead, subsea production tree, subsea tie-in to flowline system, and subsea equipment and control facilities to operate the well. It can range in complexity from a single satellite well wit a flowline linked to a fixed platform, FPSO, or onshore facilities, to several wells on a template or clustered around a manifold that transfer to fixed or floating facility or directly to onshore facilities (Bai Y. and Bai Q., 2010). *Figure 2-2* shows a typical subsea field architechure.

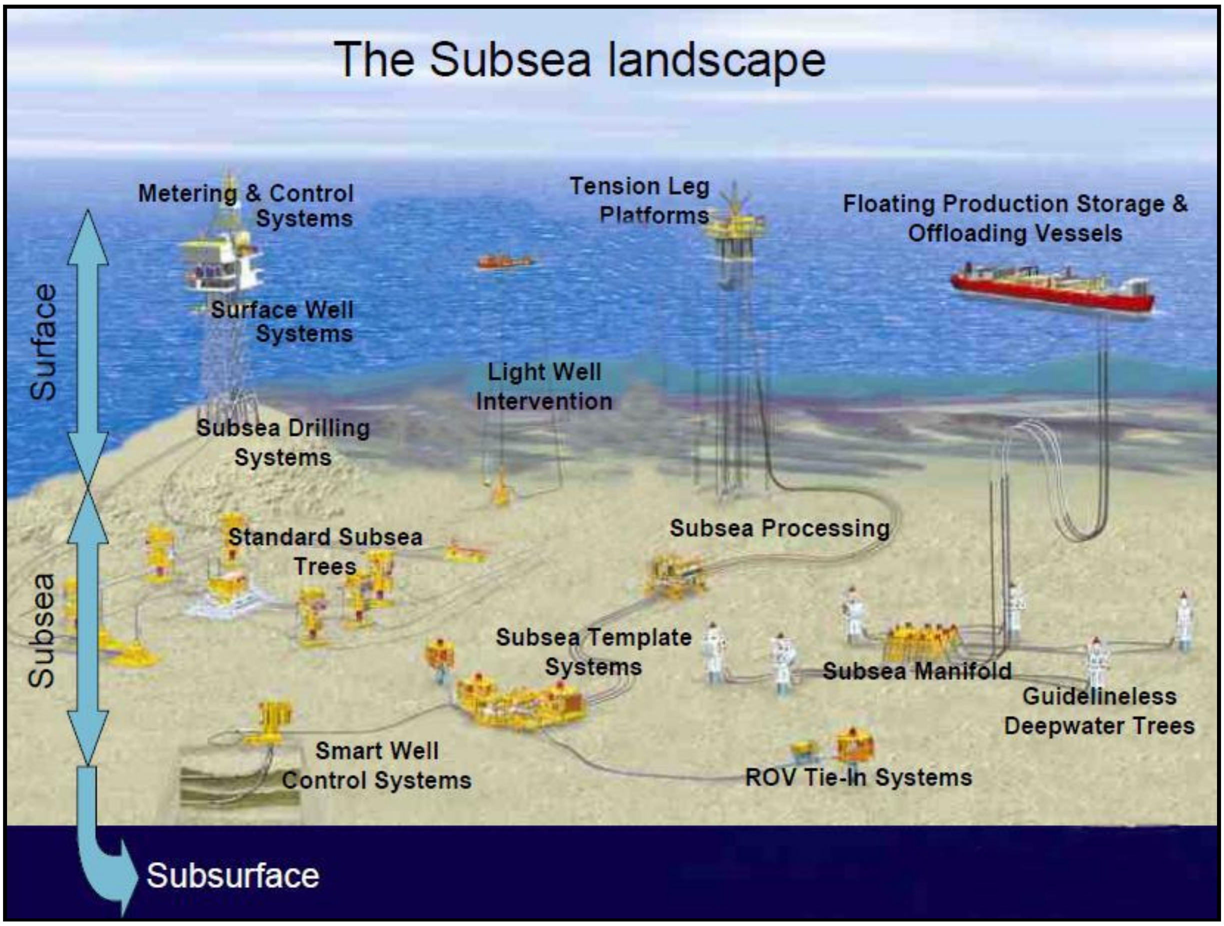


Figure 2-2 Typical Subsea Architechure (Source Schlumberger)

The subsea production system consists of the following components :

- ✓ Subsea drilling system
- ✓ Subsea Christmas trees and wellhead systems
- ✓ Umbilical and riser systems
- ✓ Subsea manifolds and jumper systems
- ✓ Tie-in and flowline systems
- ✓ Control system
- ✓ Subsea Installation

The wellhead related subsea production system can be mainly divided into Christmas tree with tubing hanger, permanent guide base, completion workover riser, workover control system. The thesis emphasis on this part of the subsea production system since the completion/WO system is part of this. Major components of this system are discussed below:

Wellhead

Wellhead is a general term used to describe the pressure containing component at the surface of an oil well that provides the interface for drilling, completion, and testing of all subsea operation phase(Bai Y. and Bai Q., 2010). The wellhead also incorporates a means of hanging the production tubing and installing the Christmas tree and surface flow-control facilities in preparation for the production phase of the well (Schlumberger, 2003). *Figure 2-3* shows a cross section of the wellhead. The wellhead incorporates internal profiles for casing suspension and tubing suspension. A subsea christmas tree will be installed on the top of a subsea wellhead and provides means to access wells during well intervention. Well head also provides guidance and mechanical support for all the operations on well.

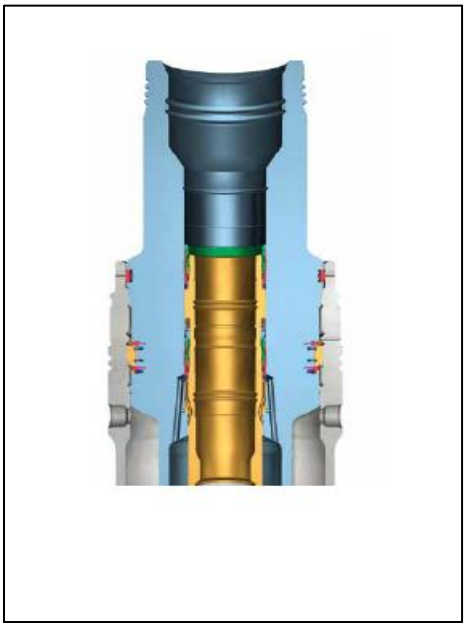


Figure 2-3 Wellhead (Source GE Oil & Gas)

Subsea Tree System

The equipment required to complete a subsea well for production or injection purposes includes a tubing hanger and a tree, often referred to in combination as the "*Subsea tree system*". Together with the wellhead system, the subsea tree and the tubing hanger provide the barriers between the reservoir and the environment in the production mode. In the installation/workover mode, the barrier functions are transferred to an LRP for vertical christmas tree (VXT) systems and the BOP and landing string for horizontal christmas tree (HXT) systems (Susbsea1, 2011). The valves in a tree be orientated either in the vertical or horizontal direction, as shown in *Figure 2-4.*

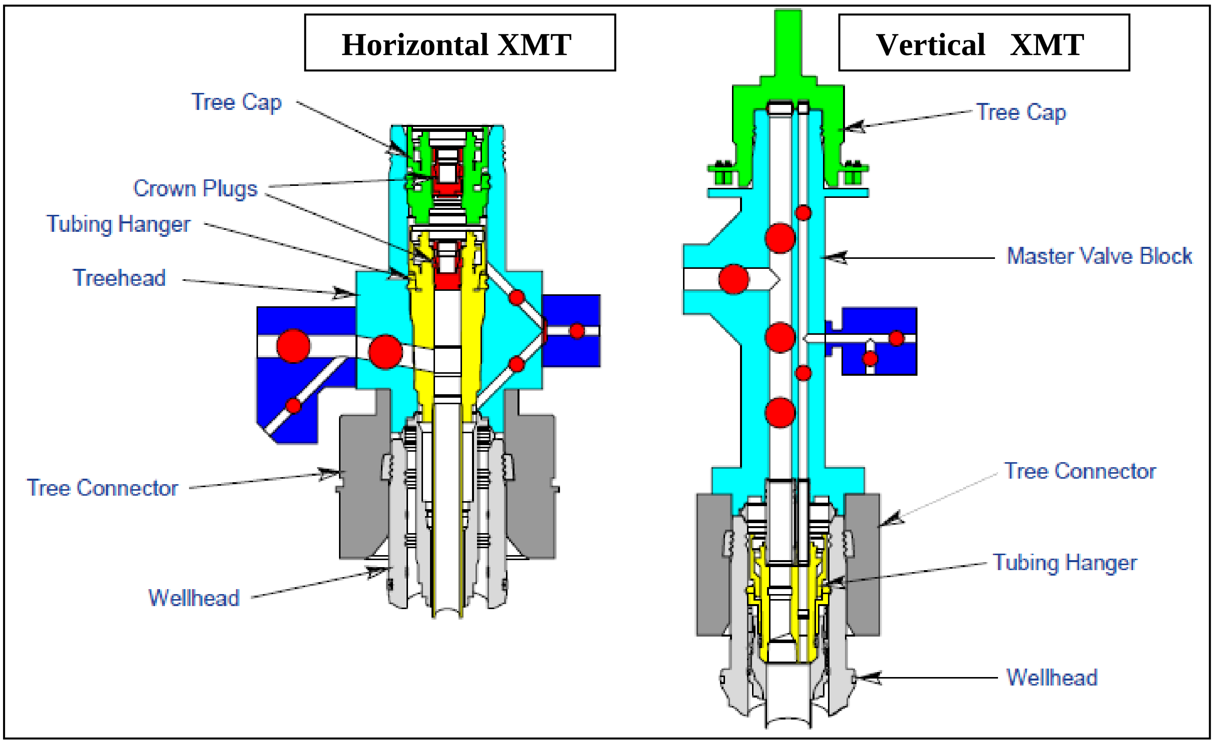


Figure 2-4 Horizontal & Vertical tree systems (Source GE Oil & Gas)

A Christmas tree(XMT) is an assembly of valves, spools, and fittings located on the top of a well. The well can be an oil well, gas well, water injection well, water disposal well, gas injection well etc. The primary purpose of XMT is to create a barrier between the reservoir and the environment. Also, the tree helps to control and monitor the flow of hydrocarbons. The other functions include :

- Allow Well Intervention.
- Safely stop produced or injected fluid.
- Accomodation of chemical injection systems.
- Accomodation of downhole control systems.
- Bleeding of excessive pressure.

Subsea trees can be either of Vertical (called conventional also) or Horizontal configurations depending on the orientation of the production master valve in the christmas tree which is discussed in the following section.

Vertical Christmas Tree (VXT) System

In VXT systems, the configuration of the master valve is above the tubing hanger. The tubing hanger is typically installed inside the wellhead and the tree is then installed on top of the wellhead. Well completion is done before the installation of the tree. Vertical trees (VXT) typically have one or two production bores and one annulus bore running vertically through their entire length (as shown in *Figure 2-4*). These bores permit the passage of plugs and tools down through the XMT and into the TH or completion string.

Horizontal Christmas Tree(HXT) System

In HXT systems, the valves are mounted on the lateral sides, allowing for simple well intervention and tubing recovery (Bai Y. and Bai Q., 2010). Hence the concept is particularly good for wells that need frequent intervention. The horizontal christmas tree is installed on the top of wellhead and then the tubing hanger is installed inside the tree. This arrangement requires the installation of the tree before completing the well.

Both the tree systems are compared in Table 2-1 below :

Table 2-1 Comparison of XMT Systems

	Vertical XMT system	Horizontal XMT system
Master Valve	Located directly above tubing hanger in the vertical run of the flowpath.	Present in the horizontal run adjacent to the wing valve.
Tubing Hanger	Run prior to installing the tree.	Landed in the tree and hence tubing hanger and downhole tubing can be retrieved and replaced without removal of tree.
Installation	Vertical XMT is normally run on a dual bore completion riser.	Horizontal XMT are run on casing tubular joint but complex landing string required for the installation of tubing hanger.
Installation Sequence	Lower completion, upper completion with installation of tubing hanger has to be completed before the installation of the XMT.	Lower completion, tree installation, upper completion with installation of tubing hanger is the normal sequence.
BOP trip	Vertical tree system has the advantage of one less BOP trip due to the installation sequence.	Horizontal tree system requires an additional BOP trip.

Tubing Hanger

Tubing Hanger (as the name indicates) is a device on which the entire tubing string hangs. The reservoir is connected to surface by long set of tubes that terminate on a tubing hanger. The tubing hanger is normally locked inside the wellhead in vertical systems and locked on a christmas tree incase of horizontal systems.

The tubing hanger performs the following functions:

- Suspend tubing string(s) at the mudline.
- Seal the annulus between the tubing and casing.
- Provide access to the production casing/tubing annulus.

- Provide through conduit(s) for SCSSV control and monitoring.
- Provide interface to subsea tree.

The selection of the tubing hanger style will determine whether the subsea tree to be used is a Horizontal or Conventional type. Horizontal subsea trees will have a concentric production bore with all of the downhole control line entry points mounted circumferentially on the outer diameter of the tubing hanger. Conventional subsea trees have two basic configurations for tubing hangers, parallel bore and concentric, but all of the downhole control line entry points will be parallel to the production bore. The choice of either of these options will affect the tubing hanger system significantly.

The parallel bore tubing hanger for conventional subsea trees consists of two or more eccentric bores through the tubing hanger body. This arrangement is mandatory for dual tubing completions and where an annulus tubing plug is to be installed. *Figure 2-5* shows both a dual bore and monobore tubing hanger.

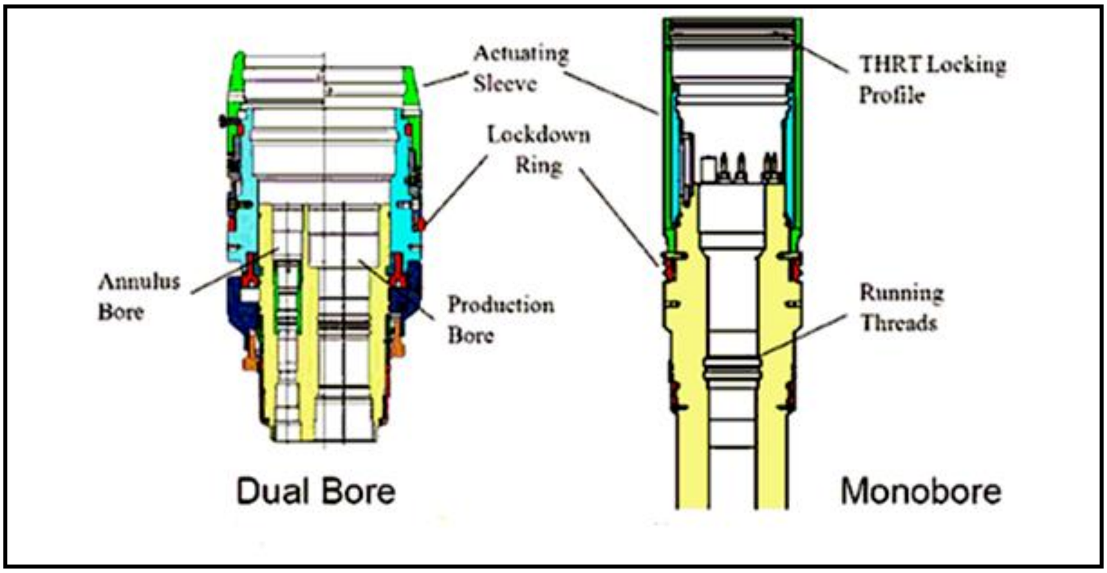


Figure 2-5 Dual bore and Monobore Tubing Hanger (Source Cameron)

Well Intervention

Schlumberger Oilfield glossary defines 'Well workover and Intervention' as

"The process of performing major maintenance or remedial treatments on an oil or gas well. In many cases, workover implies the removal and replacement of the production tubing string after the well has been killed and a workover rig has been placed on location. Through-tubing workover operations, using coiled tubing, snubbing or slickline equipment, are routinely conducted to complete treatments or well service activities that avoid a full workover where the tubing is removed. This operation saves considerable time and expense"

A well intervention, or "well work", can be more precisely defined as any operation carried out on a well, during, or at the end of its productive life, that alters the state of the well and or well geometry, provides well diagnostics or manages the production of the well (Odland J., 2010).

Refer *Figure 2-6* for subsea wireline intervention process where a monohull vessel is performing wireline operations on a well with the help of an ROV.

There are intervention methods which may, or may not require a rig. The operations without the use of a rig will be performed on live wells i.e. the well without being killed. Traditionally the subsea intervention is being done with a workover riser package which provides access to the surface intervention equipment. The workover riser serves the purpose of extending the wellbore to the surface enabling the surface equipment to access at the same pressure rating and diameter.

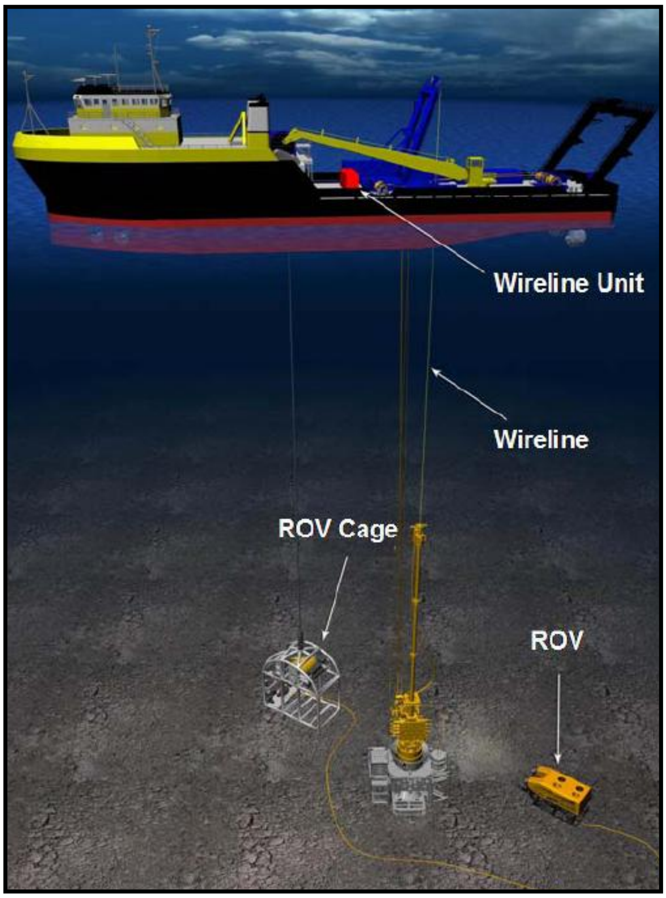


Figure 2-6 Subsea Wireline Intervention (Source Oceaneering)

Workover

The term 'workover' is used to refer to any kind of well intervention involving techniques, such as wireline, coiled tubing or snubbing. More specifically, it refers to the costly process of pulling and replacing the completion well (Odland J., 2010).

Workover rank among the most complex, difficult, and expensive types of well maintenance. They are only performed, if the completion of a well is terminally unsuitable for the job at hand. The production tubing may have become damaged due to operational factors like corrosion to the point where well integrity is threatened. Downhole components such as tubing retrievable downhole safety valves or electrical submersible pumps may have malfunctioned, needing replacement, or if the well need a recompletion (Odland J., 2010).

Figure 2-7 shows a conventional work over system with a MODU, workover rise, BOP stack, subsea tree and well head.

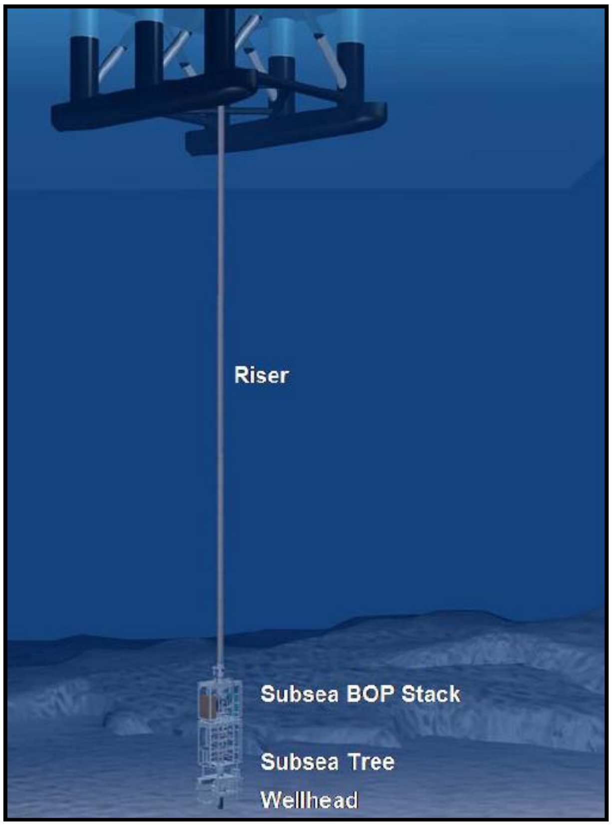


Figure 2-7 Conventional Workover System (Source Cameron)

Types of intervention

Intervention is categorized into 3 main types as listed below in *Table 2-2:*

Table 2-2 Different Categories of Intervention (Arnfinn Nergaard, 2010)

Category	Tooling	Capability
Category A Through Tubing Riserless	• Wireline	• Logging • Mechanical Work
Category B Through Tubing Through Workover riser (≈7”)	• Wireline • Small bore pipe • Coiled Tubing	• As above plus • Heavier Mechanical Work • Circulation • Rotation

Category	Tooling	Capability
Category C Through BOP(18 ¾”)	• Wireline • Small bore pipe • Coiled Tubing • Full range intervention • Full range drilling • Full range re completion	• As above plus • Re drilling • Re completion i.e. full Work Over • Well construction

Support Vessel (Typically a monohull) - Light Well Intervention (Category A)

Light well intervention typically uses a small monohull vessel with a free deck area of up to 10,000 square feet. This vessel has the capacity to perform wireline operations in combination with a subsea lubricator. They have no riser attached to the well and hence the operations are titled as “riserless” intervention. *Figure 2-8* shows the three different types of intervention.

The benchmark of the industry is 9days/well job with $150-200K/day (Schlumberger, 2006).

Semi-Submersible or Large Monohull – Medium Well Intervention (Category B)

Category B uses semi-submersibles or large monohull vessels with deck area of up to 30,000 square feet. They have the capability to handle rigid workover risers in deepwater. A standard rigid work over riser system allows conventional wireline & coiled /reeled tubing techniques to be used for downhole intervention/service work.

The benchmark of the industry is 9days/well job with $150-300K/day (Schlumberger, 2006).

Conventional Workover with a MODU – Heavy Well Intervention (Category C)

A Mobile Offshore Drilling Unit (MODU) which usually does the drilling is used to carry out Heavy well or otherwise called Category C intervention. The MODU’s will be able to handle the workover riser with the same marine drilling and handling equipment. A wide variety of operations like pulling up the production tubing strings, re-entry drilling, re-completion, sidetracking etc. falls under this category.

The benchmark of the industry is 15 days/well job with $360-840K/day (Schlumberger, 2006).

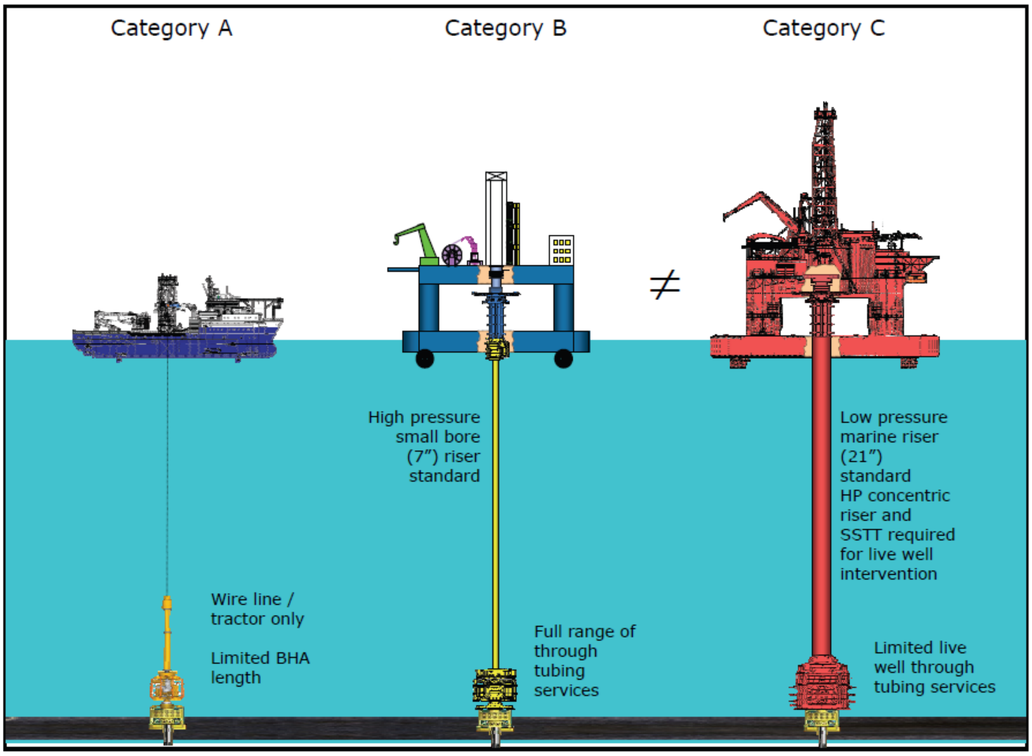


Figure 2-8 Different types of interventions (Fjaertoft L. and Sonstabo G., 2011)

With the use of conventional rig and heavy equipment, category C proves to be the costliest one where as category A is the cheapest among the three.

Figure 7-4 in Appendix A shows different categories of intervention and their comparative associated costs.

C/WO Riser system

The C/WO riser system is normally used for the following operations:

a) Well completion, i.e. run/retrieve tubing and tubing hanger through the drilling riser and BOP;
b) Run/retrieve the subsea tree;
c) Workover operations to provide wireline/coiled tubing access into the production and/or annulus wellbores.

Completion/Workover Risers(C/WO)

ISO 13628-1 defines a completion riser as

"A riser that is designed to be run through the drilling marine riser and subsea BOP stack, and is used for the installation and recovery of the downhole tubing and tubing hanger in a subsea well." The action of environmental and hyrostatic forces such as wind,waves and current has no effect on completion riser since they are run inside the drilling marine riser.

Figure 2-9 below gives an idea about the size difference between a marine riser and a work over riser.

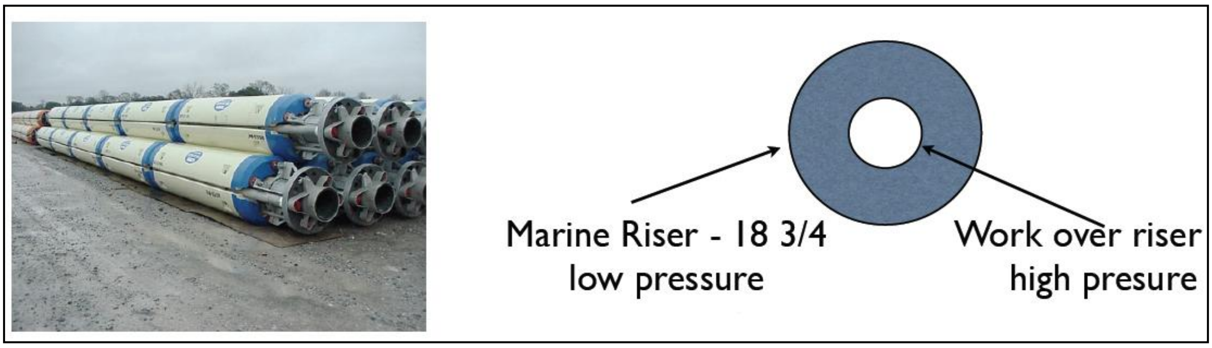


Figure 2-9 Marine & Workover riser(Janssen E., 2011)

A workover riser is a riser that provides a conduit from the upper connection on the subsea tree to the surface, and which allows the passage of wireline tools into the wellbore. A workover riser is not run inside a drilling marine riser and, therefore it shall be able to withstand the applied environmental forces, i.e. wind, waves and currents. A workover riser is typically used during installation/recovery of a subsea VXT and during wellbore re-entries, which require fullbore access but do not include retrieval of the tubing.

Table 2-3 shows the differences between marine/drilling riser, completion riser and workover riser.

Table 2-3 Comparison Marine/Drilling Riser, Completion Riser and Workover Riser

Marine/Drilling Riser	Completion Riser	Workover Riser
Large diameter pipe that connects subsea BOP stack to the surface rig.	Riser run through marine riser and subsea BOP stack.	Connects subsea tree to the surface installation/ vessel.
Used to run BOP and collects mud returns to the rig.	Used for the installation and recovery of downhole tubing and tubing hanger.	Used for installation/recovery of VXT, wireline and coiled tubing operations.
Run through the rotary of the rig.	Run inside marine riser.	Can be run inside marine riser or open water.

C/WO Riser in Tree Mode

For Open water tree mode operations, a C/WO riser is used to connect the surface support systems on a rig or vessel to the lower workover riser package (LWRP), which is latched onto the XT re-entry hub. The LWRP shall consist of a Well Control package (WCP) and an emergency disconnect package (EDP). The well intervention work to be accounted for shall include all types of wireline (WL) and coiled tubing (CT) operations, reservoir stimulation and flowing of the well for testing purposes. *Figure 2-10* shows such an arrangement.

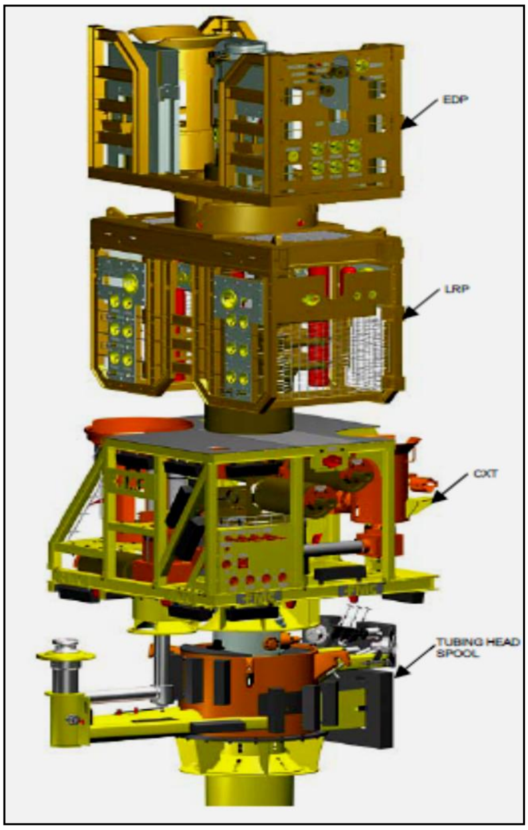


Figure 2-10 Tree mode Stack up (Source Harrold D. and Saucier B. J.)

Work over riser

There are 2 basic systems each with its own variances. *Figure 2-11* helps to understand an in riser and open water workover system.

- ✓ **An In-riser also known as a landing string** – This riser system is often used to run and test the tubing hanger. Well testing can also be done using this riser system. The riser system can be of 2 types; one with simple riser joints and the other with slick or shear joints to allow the BOP to close the well in case of an emergency situation like drive off.
- ✓ **Open Water Workover Riser System** – An open water workover riser is usually used to run, retrieve, and perform intervention with conventional trees. The riser helps in performing well entry operations such as running and setting the plugs in tubing hanger through the tree, wireline operations, or the coiled tubing operations. The different components in the system are explained in detail in the following section.

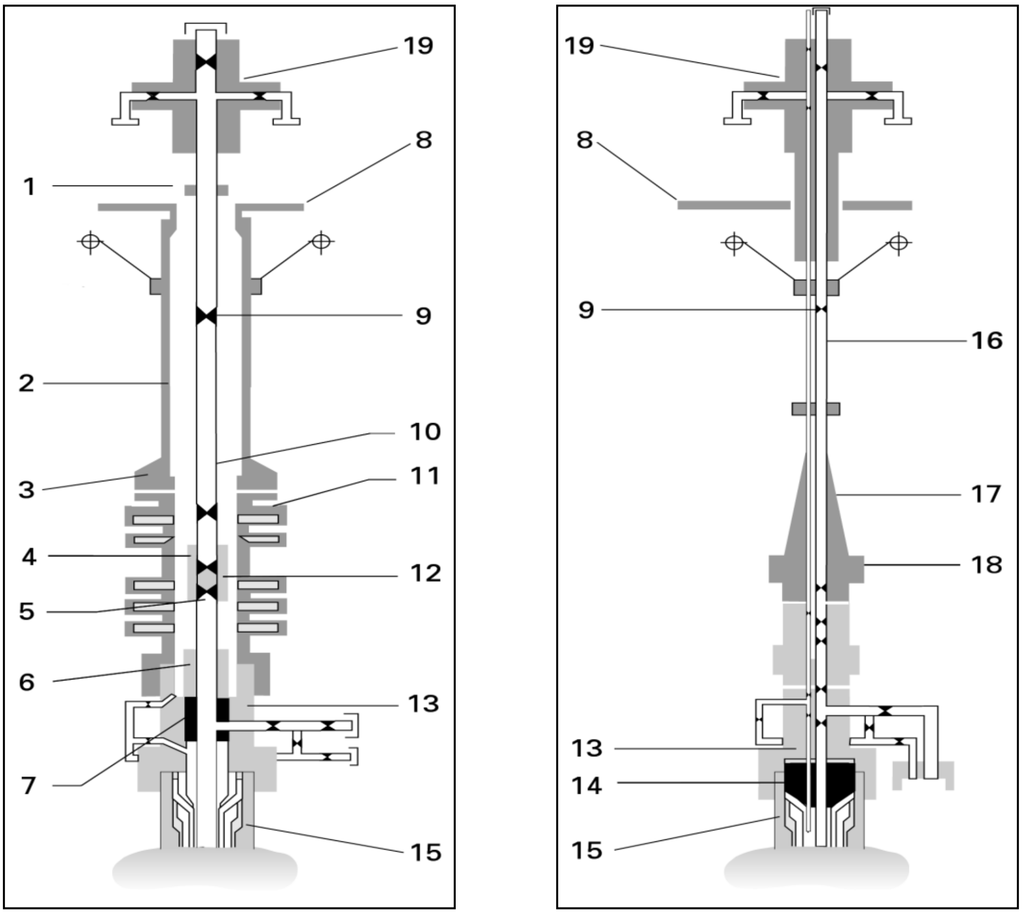


Figure 2-11 An in riser and open water riser system (Source ISO 13628-1)

1-Swivel
2-Marine Riser
3-Flex Joint
4- EDP
5-Cutter Valve
6- TH running tool
7-TH
8-Drill Floor
9-Lubricator Valve
10-Landing String
11-BOP Annular bag
12-Subsea Safety tree rams
13-Tree
14-TH
15-Wellhead
16-Workover Riser
17-Riser Stress Joint
18-EDP/LRP
19-Surface tree

Components in a workover system

Before entering into the detailed discussion about the design of the bore selector, it is quite important to know the different components in a workover system. The layout of a workover system is shown below in *Figure 2-12* and a small narration about the component follows:

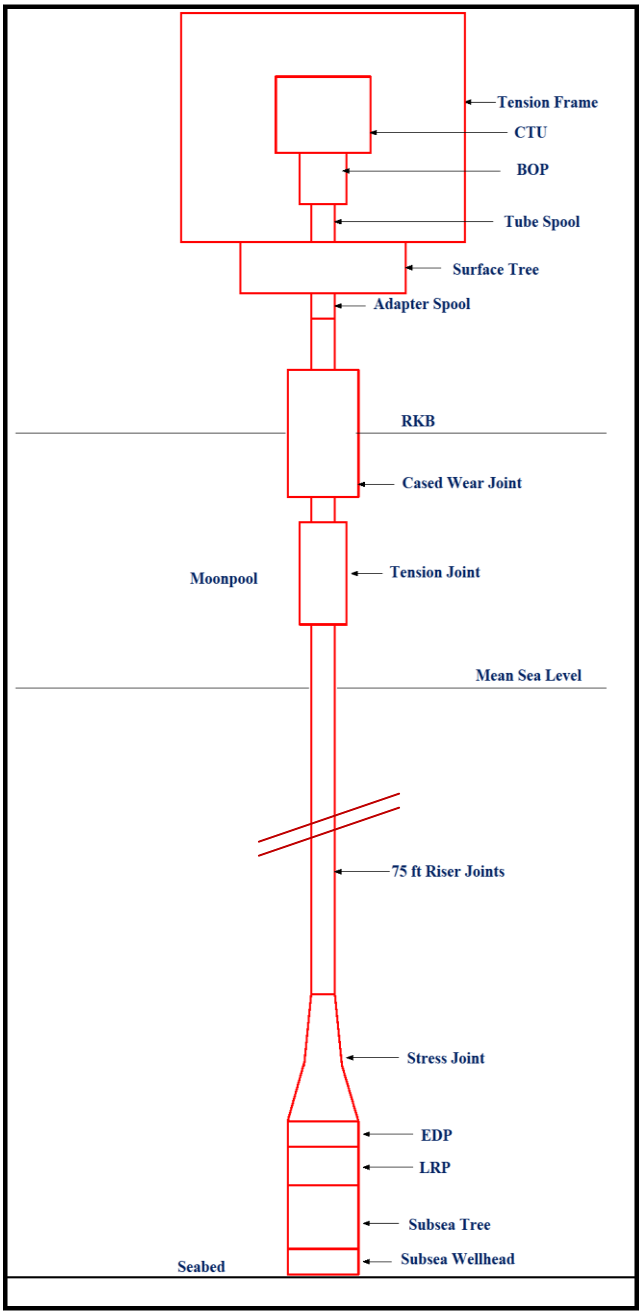


Figure 2-12 Workover riser model layout

The explanations provided here is for a general riser system and is similar in the case of T/V workover riser system. The pictures of Tordis Vigdis workover components taken during the saga fjord base visit are attached in *Appendix A*.

Surface Test Tree (STT)

The Surface Test Tree is located at the top of the riser system and provides a means of opening up or closing down production during flow testing. It also provides a means of entering into the production and annulus bores to carry out wireline or coiled tubing operations. The configuration of the STT can vary depending on the customer / field requirements. Generally, it is a dual bore unit with either manual or actuated valves in both the production and annulus bores. Usually, the surface tree consists of kill valves which are used for well stimulation or killing the well and swab valves which help in live well intervention during well testing or production operation.

Cased Wear Joint (CWJ)

The Cased Wear Joint provides protection for production, annulus pipe and umbilicals through the rotary table as the rig heaves due to wave motion. In order to provide protection to the riser joint and controls umbilical as it passes through the rotary, it is encased in a smooth casing which incorporates a slot with gates into which the umbilical is clamped.

The CWJ is designed to be a conduit for the production and annulus lines between the surface flow tree and the tension Joint. It will usually be around 40' – 45' long with an 18" diameter sleeve of between 30' – 35' of its length to allow it to remain in, and move vertically through the rotary due to the motion caused by rig heave. CWJ consists of a production line, annulus line and a centraliser sleeve. The joint is encased in a removable centraliser sleeve which is fitted along the length of the joint to prevent snagging of the joint as it passes through the rotary.

Tension Joint

The Riser Tension Joint is designed to provide a means of tensioning the completion riser string by attaching the rig hydraulic tensioner cables to the Tension Joint padeye shackles. The Joint has an effective length of generally 40 ft – 45 ft and is furnished with RL pin and box connections. The production line consists of a threaded pin up x threaded box down configuration. The annulus line passes through the main body and is fitted to support plates on the production line, with additional support for the annulus provided by equally spaced intermediate clamping bands above the main body. The bottom end of the tension joint is connected to riser joints which extend till the stress joint.

Riser joints

The RL Riser Joints are designed for workover operations and for installation of subsea christmas trees. Riser joints come in varying lengths from 5' to 45', with common lengths being 5', 10' 15', 20', 25' & 45' lengths. The usual maximum length for riser joints is 45' although there are 75' length joints, but these are more difficult to handle on the rig. So 45' is generally the maximum normally supplied length.

Riser Joints consist of a production line with an annulus line clamped to it. The production line consists of a pin up x box down configuration.

Stress Joint

The stress joint is the lowest riser joint, connected to the subsea well control equipment. The well control equipment is comprised of the Riser Disconnect Package (RDP) and Lower Riser Package (LRP), with the stress joint connected to the RDP.

The stress joint provides a transition from the dual bore (pipe) RL riser to the RDP, as well as providing a high fatigue life joint. It is configured with an RL connection up x MR Connector down.

The Stress Joint is designed to take the bending and tension of the riser due to rig and wave motion. It is mechanically connected to the RDP by means of its MR connector. This is made up on the rig prior to deployment of the RDP.

Emergency Disconnect Package (EDP/RDP)

EDP is Statoil terminology whereas RDP is GE Oil & Gas term for the same equipment. RDP provides a high angle disconnect arrangement for the open water workover riser from the LRP.

The upper section of the EDP has an MR connector profile, which allows the stress joint to be connected. At the lower end, is a 16" TR connector for interfacing with the LRP. A series of downward facing female National couplers provide hydraulic communication with the LRP. These allow control of the LRP functions as well as the ones required for the tree in workover mode. The frame of the RDP comprises of accumulators, pre-charged with Nitrogen to ensure sufficient locally stored energy is available in an emergency. If there is a requirement for a quick disconnect, the power stored in the accumulators will unlock the RDP from the LRP. It is also possible that the RDP can be run directly onto the tree and act as a Tree Running Tool (TRT).

Lower Riser Package (LRP)

The LRP is a simplified BOP usually rated up to 10,000 psi and 250 deg F, although the fail safe and system backups are getting increasingly complex.

The Lower Riser Package provides control communication to the tree via female National couplers fitted to the bottom of the LRP connector, which mate directly with upward facing couplers mounted around the tree mandrel. A similar coupler arrangement to the tree is located around the LRP upper mandrel for communication to the RDP. These hydraulic connections allow the various functions of the tree to be operated via the Workover Control System (WOCS), such as locking / unlocking of the tree wellhead / flowline connectors, valve functioning, downhole valve function etc.

The LRP production bore is generally fitted with two rams (one a shear; the other a seal ram) or a combined unit with both functions. These rams are designed to cut wireline and / or coiled tubing passing through the LRP, either through design or in an emergency. Above the rams, will usually be a shear seal valve to provide a second barrier. An actuated annulus valve is fitted for sealing purposes only, not for shearing, with a third loose actuated valve called the crossover valve for communication and circulation between the production and annulus bores, if required.

An ROV panel allows ROV intervention to override valves, rams and the LRP connector in the event of hydraulic failure from surface. The LRP interfaces with the top of the tree and provides hydraulic and electrical communication to the tree, as well as emergency barriers to the well in the event of the RDP being disconnected from the LRP to allow the rig to move off station.

Workover Control System (WOCS)

The WOCS is intended to provide the power, monitoring and control facilities to enable installation and intervention of the Xmas Tree system without impacting on other wells within the same subsea development. The system is also required to ensure that the operations carried out using the WOCS do not impact on the overall safety of the field. The system shall be designed to operate on a live well and consequently redundancy and safety features must be carefully considered.

The WOCS system includes facilities for performing normal installation and workover operations and shutdowns such as Process Shutdown (PSD), Emergency Shutdown (ESD) and Emergency Quick Disconnection (EQD) of specified functions in automatic sequences upon activation from the surface facilities.

Saga Fjord Base Field Visit

As part of the thesis a field visit to Statoil's Saga fjord base was undertaken. The base is approximately 4 hrs drive from Bergen. The purpose of the visit was to see the different components of the T/V workover system, to study about all the components and discuss with the engineers at Statoil about the workover operations. . All the Tordis Vigdis workover system equipments (except surface tree and tension joint) is stored and maintained in this base of Statoil due to the proximity of the location from the field. The T/V field is located approximately 150 km from the Saga fjord base and all the equipment logistics to the field is provided from the base.

Figure 2-13 With Statoil Engineers at Saga Fjord Base

Barrier Philosophy

The Petroleum Safety Authority of Norway defines a barrier as *“Well barriers are to prevent unintended influx (kick), cross-flow and outflow to the external environment.”* Barriers consist of one or more of barrier elements which helps to prevent the blowout from the well.

Well barriers normally consist of a primary and secondary well barrier.

The primary well barrier is intended to prevent the flow from the source i.e. it acts as the first object against the unwanted flow. The secondary well barrier serves as a backup when the primary fails to perform its purpose. It prevents the undesired flow caused by the failure of the primary well barrier.

Barrier failure or weakening is often a contributory factor in accident and incidents.

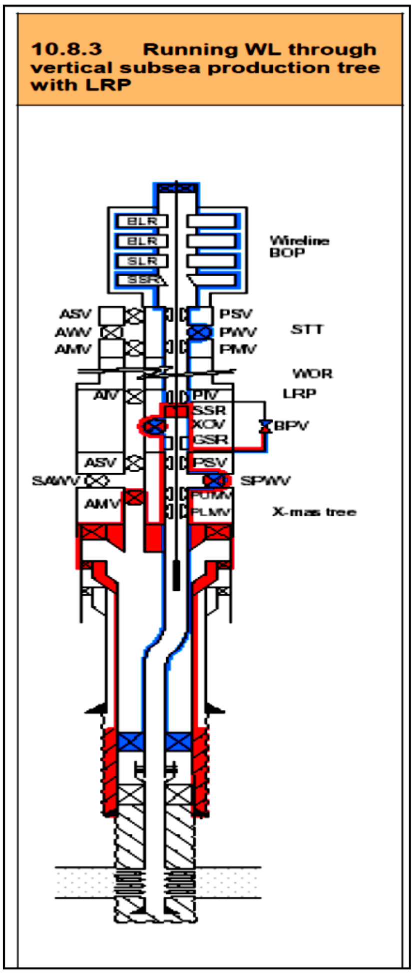
NORSOK D-010 defines the barrier philosophy as

“There shall be two well barriers available during all well activities and operations, including suspended or abandoned wells, where a pressure differential exists that may cause uncontrolled outflow from the borehole/well to the external environment.”

This uncontrolled, unintentional release of produced or injected fluids may harm personnel and environment. Hence clear, specific, concise guidance will be provided on barrier philosophy. A case specific barrier philosophy is normally adopted in case if the barrier philosophy is not defined for completion/workover activities. This is usually different from the barrier philosophy adopted during production time.

The barrier philosophy should be clearly defined with respect to the operator philosophy and local regulatory requirements.

Figure 2-14 below shows the barriers for a typical wireline operation. The primary and secondary well barrier elements are mentioned in the table beside.



Well barrier elements	Comments
Primary well barrier	
1. Casing cement	
2. Casing	Below production packer.
3. Production packer	
4. Completion string	
5. Tubing hanger	
6. Subsea production tree	Body and PWV.
7. Lower riser package	Connectors, body and x-over valve and by-pass valve.
8. High pressure riser	Workover riser.
9. Surface test tree	Body and PWV.
10. Wireline safety head	Body
11. Wireline BOP	Body only. Act as back up element to the wireline stuffing box/grease head.
12. Wireline lubricator	
13. Wireline stuffing box/grease head	
Secondary well barrier	
1. Casing cement	Common WBE with primary well barrier.
2. Casing	Common WBE with primary well barrier below production packer.
3. Wellhead	Including casing hanger and access lines with valves.
4. Tubing hanger	Common WBE with primary well barrier.
5. Subsea production tree	Body, AMV, and PWV. PWV is common WBE with primary well barrier.
6. Lower riser package	Connectors, body, XOV, BPV and SSR. Body, XOV and BPV are common WBE with primary well barrier.

Figure 2-14 Illustration of well barrier during wireline intervention(Source NORSOK D-010)

As far as the workover system is concerned, LRP serves as important well barrier equipment. From the table above, it can be observed that the body and valves in LRP form common well barrier element which are common with both primary barrier and secondary barrier. The location of the bore selector should not interfere with the barrier functions of LRP.

2.1 Need for a bore selector

A conventional subsea wellhead system integrates a dual bore tubing hanger installed within a subsea well head. The dual bore subsea tree installed on the top of the wellhead provides production and annulus flow paths and communication between the downhole safety valve, pressure, temperature gauges etc. The downhole completions are connected underneath tubing hanger. A primary barrier in the production bore is established by the setting of a plug near the downhole packer assembly. A secondary barrier is obtained by the installation of a plug in the tubing hanger production bore. On the annulus side, the downhole packer assembly acts as the primary barrier and a secondary barrier is established by the installation of a wireline set plug on the annulus access side of the tubing hanger. The wireline plugs are installed with the help of tubing hanger running tool into the tubing hanger. Hence the statutory requirement of having two independent barriers between the reservoir and environment to prevent unintentional flow for the well is satisfied. Also, this helps in well control during the time between when BOP stack is removed from the top of the wellhead and the installation of the subsea Christmas tree. Upon the installation of the dual bore subsea tree, the wireline plugs are retrieved to facilitate the production from the reservoir.

In order to access the two discrete bores of a conventional dual bore production system for the installation of wireline plugs, the normal method followed is to utilize a dual bore riser. The capital cost of such a conventional dual bore riser system is unusually high. The necessity of a bore selector arises from these conditions.

2.2 Relevant Solutions in the Industry

The aim behind undertaking an industry survey is to understand the concepts which are used as a bore selector and also to study the patents registered as bore selectors. This will help to understand the need and design requirements for a bore selector. These requirements are then used to identify and assess competing products in order to determine the benchmark and help identify areas of opportunity for competitive advantage. On investigation, the ones below in *Figure 2-15* were identified and studied. Detailed explanations about these are given in *Appendix C.*

Figure 2-15 Solutions available in market

Discussion based on background study

Traditionally, the practise in the industry was to use the concept adopted by Sonsub Inc. i.e. selection of bore access by the use of a whipstock. The production bore will be open whereas the annulus line will normally be plugged (with a wireline plug) during the operations which need production bore access. The whipstock will then be used to close the annulus bore and guide the tool into the annulus, when there is a need for annulus access. There are three extra runs needed for this concept; one for running the whipstock into the production bore, then recovering the protective cap from the annulus bore and finally removing the wireline plug from the annulus bore. This disadvantage of extra runs, which is time consuming, can be avoided by using a bore selector built as a part of the workover system.

The Expro bore selectors are also popular in the industry with the flapper embodiment as mentioned in *Appendix C* put into use. Bore selection is determined by the position of a pivoted gate, which is actuated by a cam and piston arrangement. The cam moves axially within the bore selector main housing. Cycling the cam upward selects the annulus bore; conversely, cycling the cam downward selects the production bore. An auxiliary indicator assembly provides a visual position indication of the bore selector actuation. The auxiliary indicator is hydraulically connected to the actuator. As the actuator piston reaches its full stroke for either annulus or production; ports in the actuator housing are uncovered allowing control line pressure to act on indicator piston moving it to either indicate production or annulus modes. This patented concept can be used in Tordis Vigdis workover system but with interface modifications to suit the RDP and stress joint. But, the design is based on API 6A and may require modification in order to comply with ISO 13268-7.

The background investigation did not provide much information about the other two concepts (viz. the bore selectors from Cooper industries and FMC technologies) mentioned in the *Appendix C*. Hence it's not discussed in detail here.

The bore selection method that shall be further discussed in this thesis report is based on the workover system designed for the Tordis Vigdis field. The design can be also made the basis for design of the bore selector in similar fields such as the Snorre-B, Troll etc as GE Oil and Gas is the equipment and service provider for these fields as well. There are stringent norms in the industry to comply with ISO 13628-7; the new design can be based on this standard. Since the existing workover system is a GE design, the interface issues can be more easily addressed with a bore selector developed within the company. There is always risk of interface issues while buying a bore selector available in the market and integrating it into GE workover system. Due to the aforesaid factors and considering future product cost savings it is highly desirable that GE Oil and Gas design and develop their own bore selector.

In the coming sections, the task is to go ahead with designing a bore selector to suit the workover system. But first of all let's write all the requirements and specifications needed to design a bore selector.

2.3 Design Requirements

The design process begins with the customer requirements. The goal is to completely understand the problem/task, define it clearly and fully as possible, and lay the foundation for the design. The design requirements may be mainly functional and non functional requirements. But, in the thesis the discussions are mainly concentrated on the functional requirements.

The bore selector should

- Facilitate transforming a dual bore riser system to a monobore system.
- Allow the wireline tools to access production and annulus bore.
- Allow coiled tubing in the production bore.
- Be actuated from surface or via an ROV using hydraulic, mechanical means.
- Be fail as is to production and annulus.
- Have a position indicator to confirm the accessed bore.
- Be pressure containing.

2.4 Design Specifications

- Water depth = 300 m (Tordis/Vigdis)
- Maximum working Pressure = 69 MPa or 10,000 psi (*Table 7-1*)
- Temperature Classification = K (Operating temperature min 0°F(-18°C), max 250°F(121°C) as per *Table 7-2*)
- Production bore = 5.125" Annulus bore = 2.875"
- Material Class = DD (sour service as per *Table 7-3*)

Interfaces

The upper profile of the bore selector should interface lower end connection of the stress joint (Quick fit MR Connector- box) and the lower profile should interface with the upper end connection (Quick fit MR Connector- pin) of RDP.

2.5 Location of bore selector

The thesis concentrates only on the 'tree mode' and **not** the 'tubing hanger mode' in the vertical system. When considering the design of the bore selector, one of the vital points to be discussed is the location of the bore selector i.e. where the bore selector shall be positioned as part of the workover system. The location should not interfere with the functional requirements of the whole workover system as such. Also, depending on the location, the bore selector may sometimes have to serve as a barrier element. Hence the presence of bore selector should not wane the barrier functions of the workover system, if acting so.

Let us first look at the position of the bore selector in companies which currently use a bore selector and in some of the patents registered. The *Table 2-4* Location of the bore selector in available solutions below captures them all. This is being taken from the section above in which the investigation on the relevant industry solutions has been described.

Table 2-4 Location of the bore selector in available solutions

Solutions available	Location of the bore selector
Sonsub bore selector	The upper part connected to stress joint and the bottom to the top of EDP.
Cooper Industries Inc.	Riser in top and wellhead at bottom via Tubing Hanger Running Tool (THRT).
Expro North Sea Limited	a) Disposed between LRP and subsea christmas tree. b) Between monobore riser and the dual bore subsea test tree
FMC Technologies Inc.	Between monobore riser and EDP with retainer valves in linking

From the table, it could be understood that there is no general rule followed as such with respect to using the bore selector in a particular position. But importance should be given that it should match the functional and operational requirements of the workover system. Besides, there are locations (for e.g. LRP and subsea tree) where bore selector may have to act as a barrier element.

Let us discuss some of the possible locations where the bore selector can be positioned. The discussion will start from bottom (i.e. from above the wellhead upto surface)

On the top of the christmas tree (i.e. between christmas tree and LRP)

The location of the bore selector will be below the WCP. The arrangement comprises of mono bore riser with mono bore LRP with a flexible hose for annulus circulation. This location of the bore selector increases the stack height of the system. *Figure 2-16* shows this arrangement.

The bore selector design should be strong enough to withstand heavy loads from the workover riser components comprising of LRP, RDP, and riser joints. But these loads will be comparatively less due to the monobore riser design when compared to a dual bore riser workover system. With this kind of arrangement, there is possibility of fabricating the monobore LRP, RDP which can be advantageous when considering the cost and weight of these equipments. Another important factor that should be considered with this design is the bending moments incurred during an intervention / workover operation.

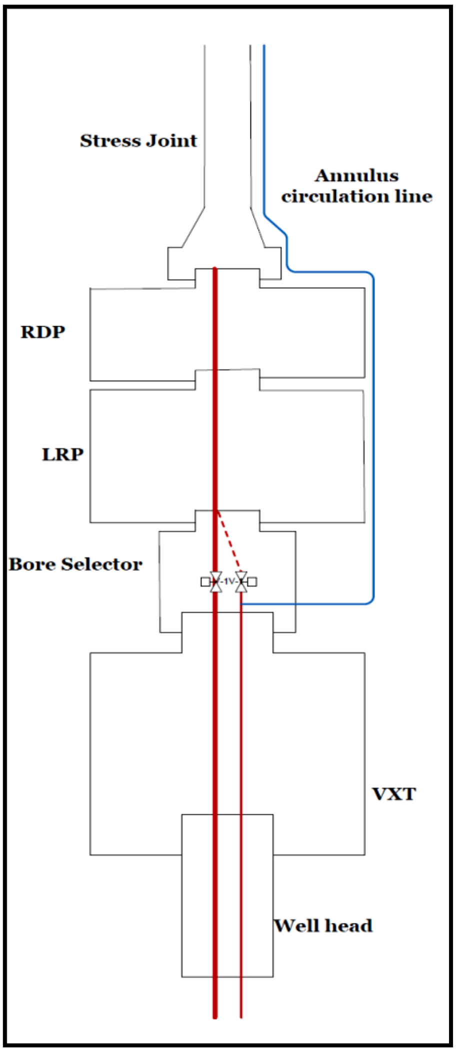


Figure 2-16 Bore selector located at the top of the tree

Normally, this is taken up by the stress joint. But in this particular location of the bore selector has to with stand huge loads and bending moments, due to the increased stack height. Also, in this particular location the bore selector becomes part of barrier element. Hence assessment has to be done regarding failure to perform their intended function in a given scenario. Valves are included in both the bores inside the bore selector to allow for sealing purpose and for individual access to both the bores.

Table 2-5 lists pros and cons of this location.

Table 2-5 Pros and Cons of positioning bore selector on top of tree

Pros	Cons
Monobore riser allows faster running time of the C/WO system.	The bore selector design is complex with inclusion of valves inside the bore selector.
Reduced weight of the entire system with monobore riser, EDP and LRP and subsequently less load on the well head.	High stack height and hence higher bending moments.
Simplifies LRP design by eliminating the annulus line.	Limited life of flexible hose.

Pros	Cons
CAPEX reduction on a longer perspective.	Time consuming process since RDP and LRP design also has to be modified to a monobore design.

Between RDP & Stress Joint

The bore selector will be positioned in between RDP and stress Joint with a flexible hose from the surface for the annulus circulation. In this case, the bore selector can be made upto the stress joint and both of them can be made to run as a single unit through the rotary table. Thus the equipment being stacked-up in preparation for running will comprise of VXT, LRP and RDP. The conduit from surface can be made into a single bore till stress joint followed by dual bore RDP and LRP. The bore selector located on top of the EDP allows tool access to both bores. *Figure 2-17* shows the arrangement.

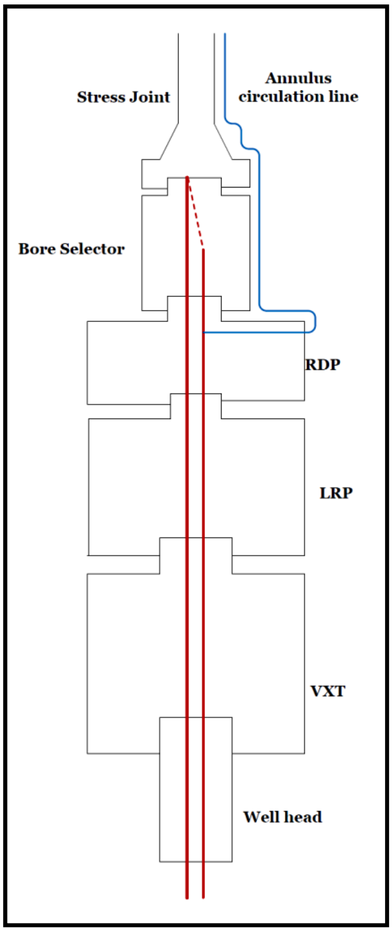


Figure 2-17 Bore selector located between Stress joint and RDP

The mono-bore riser offers somewhat easier make-up and subsequently faster running times when compared to a dual bore riser, although it is difficult to quantify this advantage. It also opens up for the possibility of using standard rig tools for make-up and break-out of the connections.

The heavier components like RDP and LRP does not require big make shift in this case. The presence of stress joint above the bore selector helps to take the bending moment. Hence the workover system can be put into use within shorter time period since there are no big design modifications in RDP and LRP. In this case the bore selector does not have to take any barrier functions. The presence of a telescopic joint will allow increased weather window for running wireline operations. Refer *Table 2-6* for the pros and cons of this location of the bore selector.

Table 2-6 Pros and Cons of locating bore selector between RDP & Stress Joint

Pros	Cons
Monobore riser helps in easier make up and less running time.	Limited life of flexible service hose.
Less drag on the riser string with slightly increased operating envelope as compared to a dual bore riser.	
Bore Selector has no barrier functions in this particular location.	
Less time for making the C/WO put into use since there are no modifications associated with RDP and LRP.	
Easier handling by the riser handling equipments due to reduced weight.	
Industry recommended position.	

Along with tension joint

This concept is very similar to a normal workover riser system with dual bores. The new system comprises of a bore selector with tension joint and a telescopic joint. *Figure 2-18* shows the location of the bore selector. A telescopic joint should be made part of the system for allowing more weather window for the wireline operations. The telescopic joint compensates for heave and offset of the vessel and is available for all riser systems. This movement is achieved through the stroking movement of the inner and outer barrel of the telescopic joint. But currently there is no dual bore telescopic joint available in the market. Hence expect more downtime waiting on weather for suitable weather window with this position for the bore selector.

Table 2-7 Pros and Cons of positioning bore selector along with tension joint

Pros	Cons
Service life more due to the presence of annulus line.	More downtime due to waiting on weather.
Bore Selector along with telescopic joint increases the cost of the entire system.	There is little difference in running speed as compared to a monobore riser.
No flexible service line need for annulus circulation.	Development of telescopic joint is a constraint in this case.
	System complexity in designing and operation.

To allow the use of a telescopic joint with a dual-bore riser string a bore selector can be integrated with the tension joint. The choke and kill lines system for the marine riser will be hooked up to the annulus bore through the tension joint and tension ring. A 2” valve must be included below the bore selector to allow circulation and kill. The 2” annulus line will be more durable than a flexible hose and life expectancy is much more than a flexible hose. The dual bore system can be considered more robust than one relying on a flexible hose.

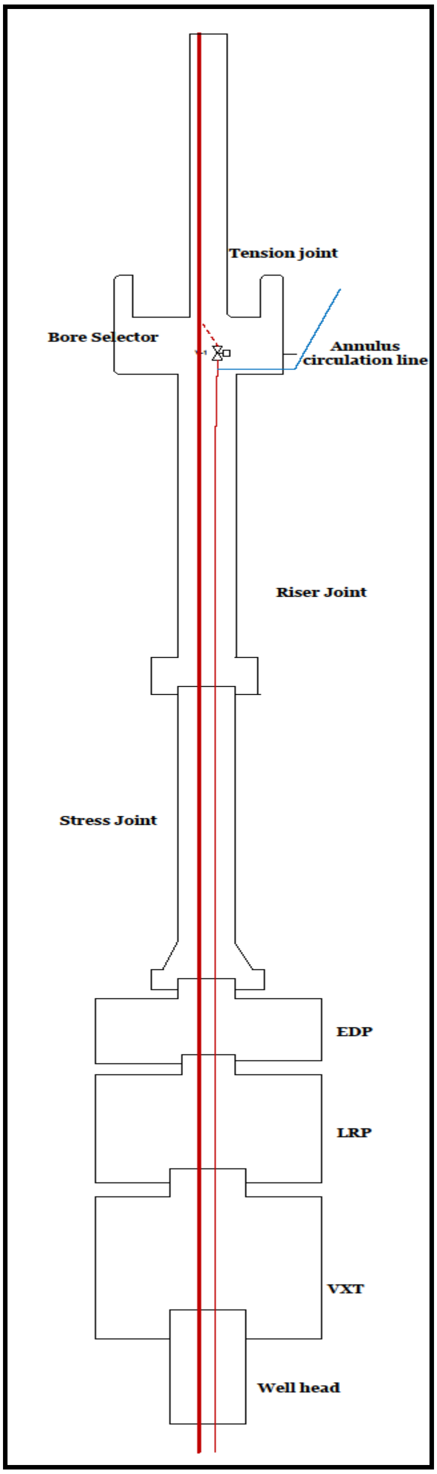


Figure 2-18 Bore selector along with tension joint

Conclusion on the location of bore selector

Based on the above discussions, and referring to the pros and cons with respect to each location, it can be concluded that the best position to have the bore selector is between stress joint and EDP since it has minimum disadvantages. Moreover, GE oil and gas considers this as the preferred location. Expro bore selector available in the market is being used in this position. The major advantages are minimised bending moments, no associated barrier element functions, no heavy loads of LRP, RDP, trees etc. Also, ISO 13628-1 recommends the preferred position to be between stress joint and EDP. This can be referred from the *Figure 2-19* taken from ISO 13628 -1 showing position of the bore selector.

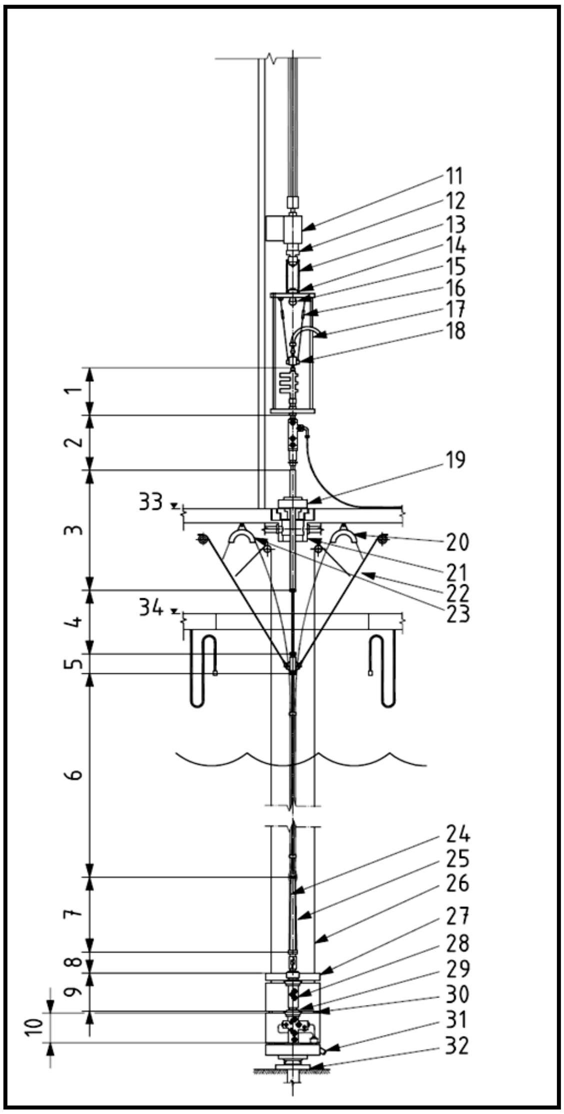


Figure 2-19 Running of VXT on monobore completion/workover riser with bore selector (Source ISO 13628-1)

1 – W/CT BOP
2 – SXT + adapters
3 – Wear joint
4 – Spaceout joint
5 – Tension joint
6 – Casing tubing joint
7 – Stress joint
8 – Bore selector
9 – Lower WO riser package
10 – Xmas tree (XT)
11 – Travelling block
12 – Top drive
13 – Balls
14 – Elevator

15 – Winch
16 – Strops
17 – Lifting frame (shown as example)
19 – Completion riser spider
20 – Annulus access line sheave
21 – Tensioners
22 – Diverter housing
23 – WO umbilical sheave
24 – WO controls umbilical
25 – Annulus access line
26 – Guidelines (optional)
27 – Emergency disconnect package (EDP)
28 – Wireline/coiled tubing BOP (W/CT BOP)
29 – Tree running tool (TRT)
30 – Guideposts (optional)
31 – Guidebase
32 – Drilling guidebase or template slot
33 – Drill floor
34 – Moonpool

Global riser analysis can provide us with the stress values confirming the suitability of placing the bore selector in between stress joint and EDP.

3 CONCEPTUAL DESIGN

This part of the thesis gives birth to an idea by a rough sketch or words which can be later developed into a future product. From this thought, start refining the idea into a product design which can work as a solution.

“If you generate only one idea, it will probably not be the best solution; if you generate several ideas, then you will likely have an excellent solution.” - Anonymous.

This section of the thesis will discuss some of the concepts developed, and these concepts will be evaluated on certain criteria which must be fulfilled as part of their functional and operational requirements. All the concepts will be ranked and the best will be chosen for further development. *Figure 3-1* shows an open water bore selector in the market.

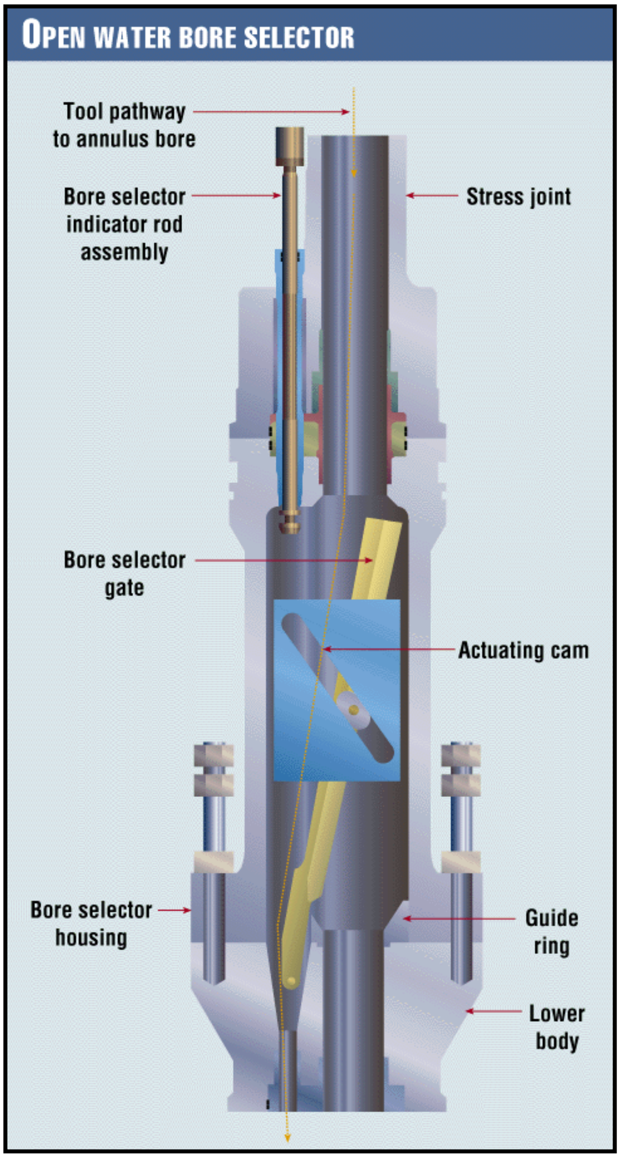


Figure 3-1 An open water bore selector available in market (Source Oil & Gas Journal)

Concept 1 out of 4 – Flapper Concept

This is a simple concept consisting of a flapper fixed on a hinge. The hinge location will be at the bottom of the bore selector body and in between the two bores viz. the production and annulus. The flap covers the annulus when access to production bore is required and similarly it covers the production when access to annulus is required. The entrance to both the bores at the bottom of the bore selector is chamferred to make it easier for the tool string travel. *Figure 3-2* shows a simple concept but it may have to be a more sophisticated one when going to have in detailed design.

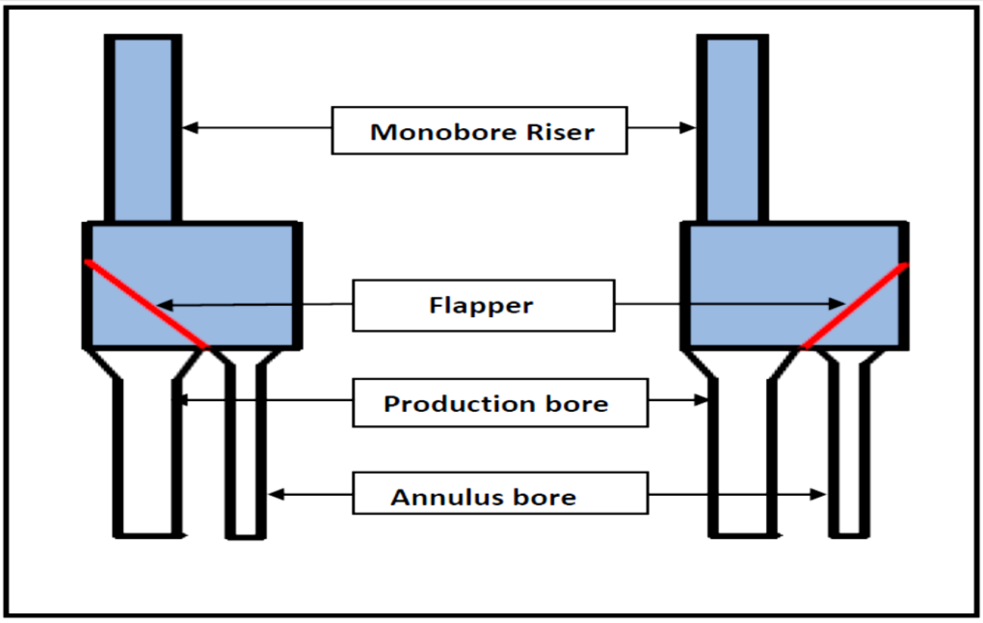


Figure 3-2 Flapper mechanism

Concept 2 out of 4 –Tapering Mechanism

This concept is based on a movable metal block which encompasses the production and annulus bore inside the bore selector housing. In the normal mode, the production bore will be open without any significant movement of the metal block as shown in *Figure 3-3.* The annulus bore will be tapered to guide the tool string. The bottom part, which connects the bore selector to the EDP and the top part of the annulus line inside the movable metal block will be tapered to make sure that the tool is guided properly inside without any obstruction. The movement can be obtained manually by ROV or by a hydraulic system connected from topside. The rotation of the rod through a threaded connection makes it possible to move the solid block inside the housing. The design will be based on the concept that ROV will be able to turn the rod which in turn can move the metal block.

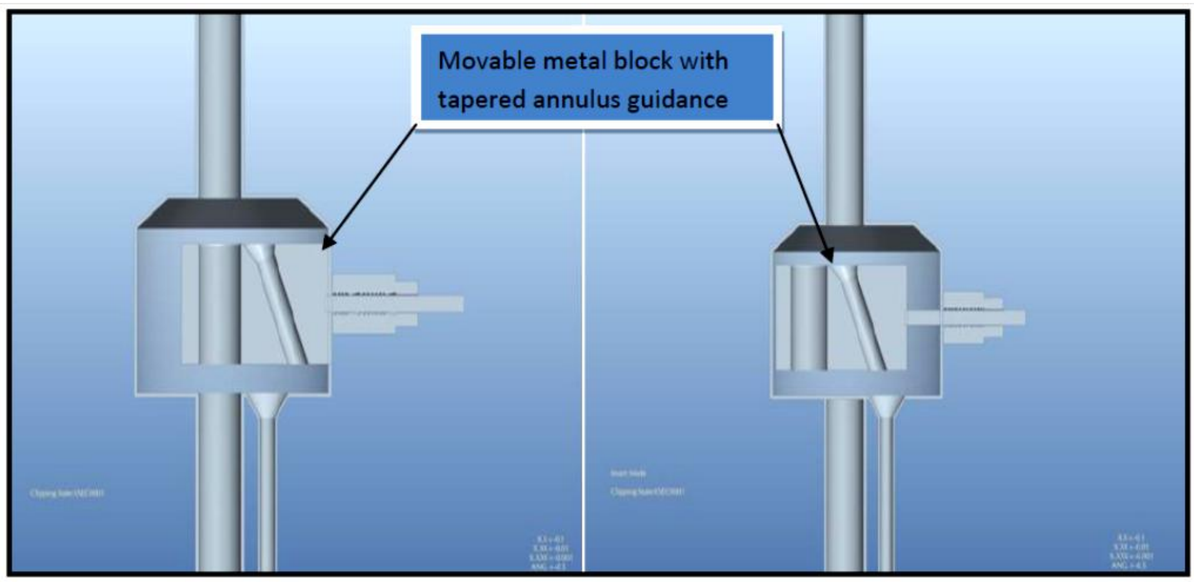


Figure 3-3 Bore Selector with movable metal block

Concept 3 out of 4 – Actuator Mechanism

This concept consists of a solid block inside the bore selector housing which has a 5” opening for the production bore and a 2” opening for the annulus line. Refer Fig 3. to understand the shape of the concept. The 5” bore will be closed by a horizontally travelling actuator which is manually operated by ROV. A certain number of turns of the actuator will close the 5” production bore. Even though, the annulus bore will be open at all time, travel to annulus is possible only when the production bore is closed. The normal travel of a tool is through production bore which is much bigger and the tool will be mislead if there are big heave motions with the vessel. The travel of the tool to the annulus will be guided by a draft made on the top of the block itself. The bottom end of the bore selector which connects to both bore will be slightly tapered, which makes an easy access to the respective bores. *Figure 3-4* provides a cross section of the inside mechanism. This concept has the speciality of which both the bores will be open when there is an access needed to production bore. Hence the design should must make sure that the wireline or coiled tubing tool enters the correct bore during intervention.

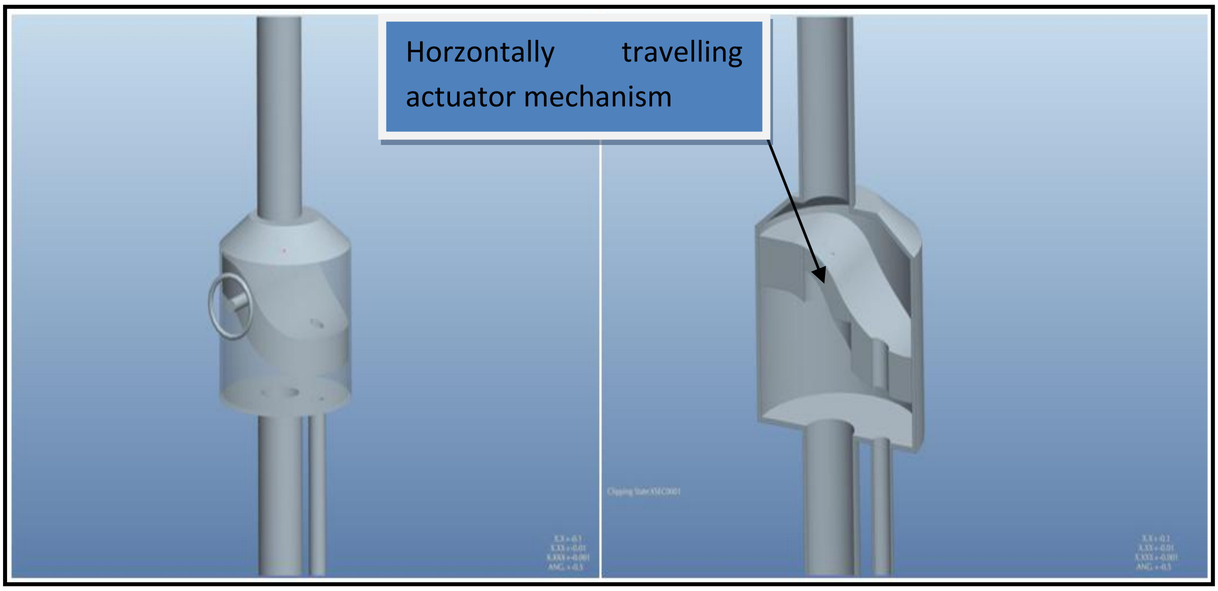


Figure 3-4 Actuator mechanism inside the bore selector mechanism

Concept 4 out of 4 - Pivot Mechanism

This bore selector concept consists of a pivoted arrangement which is free to move when required access to the specific bore is needed. *Figure 3-5* shows the concept. The movement will be initiated by ROV from outside the bore selector. The guidance mechanism inside the bore selector will be in a straight position when providing direct access to the production bore. This allows the tool to pass through the monobore riser from top and straight into the production bore without any hindrance. When the pivot is tilted from outside the bore selector, access to the annulus bore is obtained. The mechanism has enough length, which reaches the top of the bore selector housing and guide any tool that need to be run in the annulus. Also, this mechanism has to include a stopper to make sure that the tool does not overrun the hole meant for accessing the annulus bore.

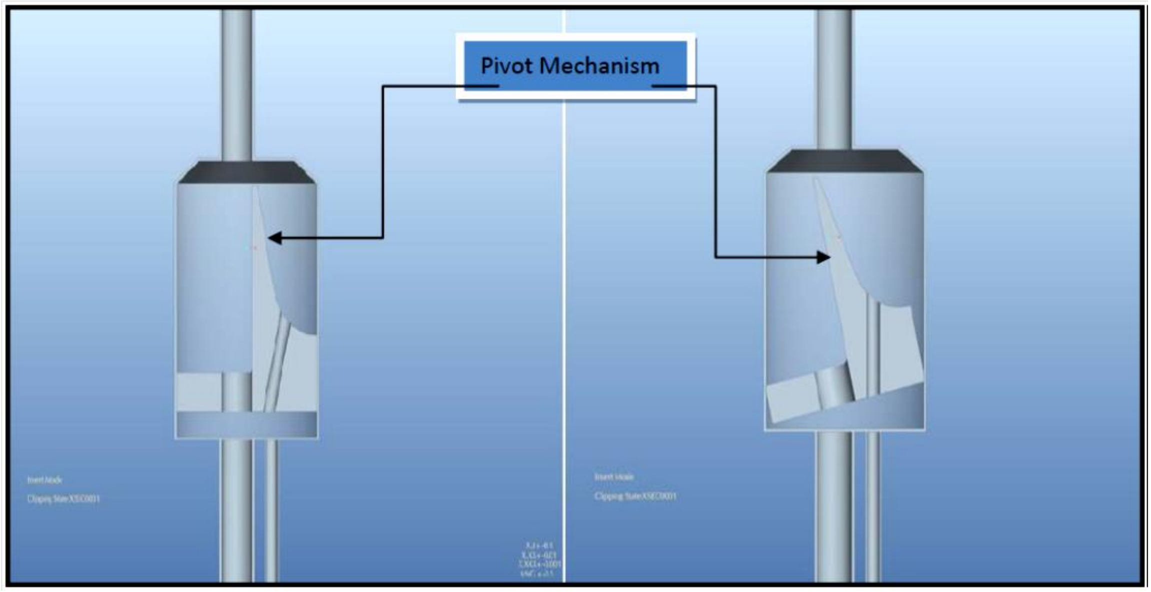


Figure 3-5 Bore Selector with Pivot mechanism

3.1 Criteria for evaluation

The conceptual designs created should be comparatively evaluated using the same checklist criteria. A list of parameters is set for evaluating the concepts developed. This will be mainly focussed on their functional requirements and easiness by which different concepts can be developed into a product fit for use.

The following are the main checklist criteria on which the bore selector concepts are evaluated:

1. Guidance Mechanism
2. Operating Mechanism
3. Minimum Size
4. ROV Access
5. Operation Time
6. No Patent related issues
7. Technical risk
8. Need for product qualification

These checklist criteria are weighed according to their significance in the bore selector functionality, use and development, as a product. The explanations of the each criterion are described below for better understanding of how the bore selector concepts were evaluated.

Guidance Mechanism

This criterion considers how well the bore selector mechanism can guide the wireline or coiled tubing tools. The major consideration would be the ease with which the tools can access the production or annulus bore; the tool on its way should travel without obstruction. This is of prime importance since the guidance mechanism also governs the shape of the bore selector mechanism. Due to the significance of this mechanism, weightage is done at a maximum score of ’5’.

Operating Mechanism

This is considered to be one of the main factors that need to be well thought in the design. There are options like mechanical (ROV controlled), hydraulic (controlled from topside), cam mechanism etc. to operate the bore selector. The discussion mainly considers ROV operation as primary mechanism with hydraulic as as back up or vice versa. Cam mechanism is also currently used in the industry. The weightage allotted is ’3’.

Minimum Size

The diameter of the bore selector housing is always restricted by the rotary table size. The designed size should not be more than the diameter of the rotary table which make it impossible for the bore selected fitted on the workover riser to pass through the rotary table. Minimising the size will help in reducing the overall weight and will make it easier for the handling equipments in rig to hold the workover system. Exact size will only be known in the layout phase in the design process. Minimum size is a desired characteristic and not of great implication in the conceptual design stage. Hence the weightage proposed is ’1’.

ROV Access

ROV has an important role in checking if the bore selected is the correct one or not. The selected design should have ROV access which will help to operate the bore selector manually (as primary or back up operating mechanism) and could also help to check indicator mechanism. The indicator mechanism can confirm if the selected bore is correct or not which will be verified by ROV. It is an important function if the preliminary operating mechanism is through ROV. ’3’ can be considered as a good weightage for ROV access.

Minimum operating time

The whole concept of designing a bore selector is built to reduce the cost and running time. Hence a mechanism which can easily switch between the production and annulus bore can help us to save the running time. This criterion implies the ease (with time as the factor for measure) with which the operation can be switched from one bore to the other. The weightage provided is ’3’.

No patent related issues

There are only few bore selectors available in the market and also some patents filed on concepts of bore selector. It is imperative to study the patents existing and should carefully design the bore selector that there should not be any patent related claims in the future. Interference with a patent can lead to legal troubles and hence this can be considered critical for the design. So weightage of ’5’ is given.

Technical risk

There is always risk associated with the development of new products especially when there are only few successful products available in the market. The questions that come in mind is “Has it been done before?” If ‘No’ the risk is Very High. The next question is “if it was done before, then was it done successfully?” Then risk is moderate to high. This criterion is crucial especially when designing a new product. The technical risk also helps to identify and rank the probable failure modes with probability of failure and consequence of failure. The weightage for evaluation is ’3’.

Need for product qualification

DNV RP A203 defines qualification as ”Qualification is a confirmation by examination and provision of evidence that the new technology meets the specified requirements for the intended use.” The qualification results help us to implement new technology and compare alternative technologies. ISO 13628-7 states that “The manufacturer shall complete qualification testing on any unproven component to be used in the C/WO riser system or provide suitable documented evidence of its performance from actual operational/field use.” All the new developed products should pass through hydrostatic or gas pressure testing, pressure and temperature cycling testing, maximum(and combined) load testing, function testing, fatigue life testing, life cycle/endurance testing. Product qualification comes at later stage after creating the prototype. Hence the weightage is ’1’.

Giving credit points to evaluation criteria -: Good - 3, Average- 2, Bad – 1
High -1, Medium -2, Low - 3

The concepts developed will be evaluated according to the desired attributes and then ranked. The top ranked concept will be considered for further design with detailed drawing, analysis and calculation. See *Table 3-1* below for ranking.

Table 3-1 Ranking using evaluation criteria

	Concept 1 Flapper Concept	Concept 2 Tapering Mechanism	Concept 3 Actuator Mechanism	Concept 4 Pivot Mechanism
Guidance Mechanism(5)	Good(3) 15	Average(2) 10	Bad(1) 5	Good(3) 15
Operating Mechanism(3)	Good(3) 9	Good(3) 9	Bad(1) 3	Good(3) 9
Minimum Size(1)	Good(3) 3	Bad(1) 1	Bad(1) 1	Average(2) 2
ROV Access(3)	Bad(1) 3	Good(3) 9	Good(3) 9	Bad(1) 3
Minimum Operating Time (3)	Average(2) 6	Average(2) 6	Good(3) 9	Good(3) 9
No Patent related issues(5)	Bad(1) 5	Good(3) 15	Good(3) 15	Good(3) 15
Technical Risk(3)	Medium(2) 6	Less(3) 9	High(1) 3	Less(3) 9
Need for product qualification(1)	Medium(2) 2	Medium(2) 2	Medium(2) 2	Medium(2) 2
Total Score	**49**	**61**	**47**	**64**
Rank	**III**	**II**	**IV**	**I**

Referring to the above table, it can be observed that pivot mechanism has turned out to be the best mechanism out of the four concepts evaluated based on the criteria discussed. Hence, this mechanism is selected to proceed further with drawings and calculations to develop the product. In the conceptual design, only the raw concepts were discussed and, the selected concept takes shape during the next stages of design.

4 DESIGN OF THE PREFERRED CONCEPT

At this stage of the design process, the chosen concept if the bore selector is given shape and form. It is developed into an assembly showing the relative positions of the various components, their sizes, shapes and inter relationships. The embodiment design typically involves a large number of iterative/corrective steps to gain the final shape. Generally, the embodiment stage will begin with the identification of potential materials and production techniques and then establish the form and shape.

The location is already being fixed (i.e. between stress joint and RDP) before as per the discussion in Section '*Location of bore selector*' . So, during design it is easier to keep same interface with bore selector rather than going for new connectors, which is time consuming. The RDP, LRP and VXT will be stacked and run together in case of VXT installation. Usually, stress joint along with riser joints are run through the rotary table. The riser stress joint pipe at the bottom end is welded to a flange.This flange is connected to MR connector with the help of bolts. The MR connector fits on to the top of RDP.

4.1 DRAWINGS OF THE PREFERRED CONCEPT

In the designed layout, the bottom end of the stress joint along with the flange will be connected to the top of the bore selector housing. The bore selector mechanism will be inside the housing. Refer *Figure 4-2 and Figure 4-3* to find the mechanism. The bottom end of the housing will be welded to a metal piece which has similar shape and dimensions in the workover system of the T/V field. So this metal piece will be again welded to the MR connector and the connector interfaces with RDP. *Figure 4-1* shows the embodiment.

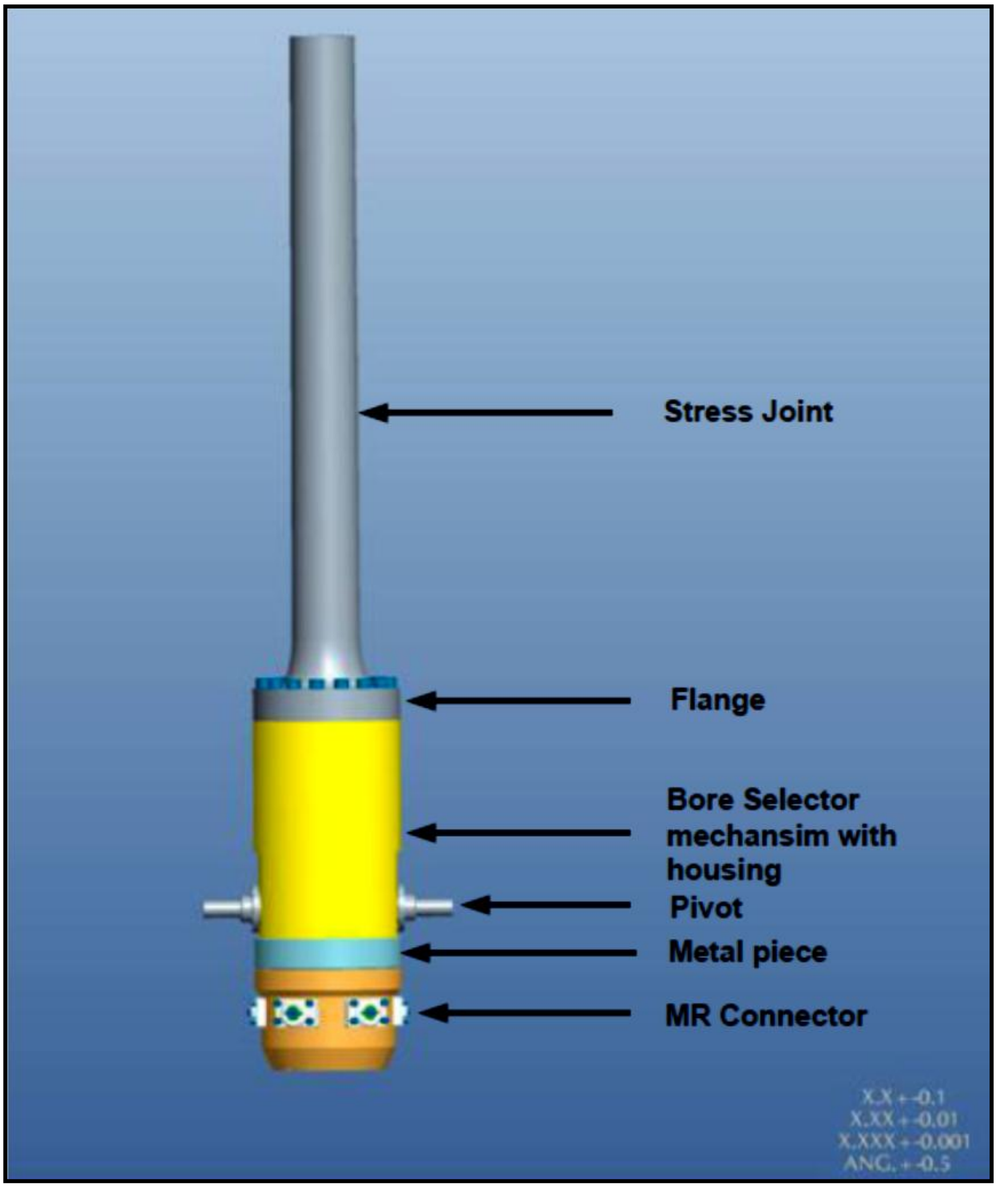


Figure 4-1 Bore Selector Assembly

The internal diameter of the bore selector is fixed to 20”. Hence the bore selector mehanism which has to be placed inside the housing has to be designed to a diameter less than 20”.

Here in this preferred conceptual drawing the mechanism has a diameter of 19.25" (See *Figure 4-2*). However, design is an iterative process and hence, if these dimensions adopted are found to be unsuitable has to be changed.

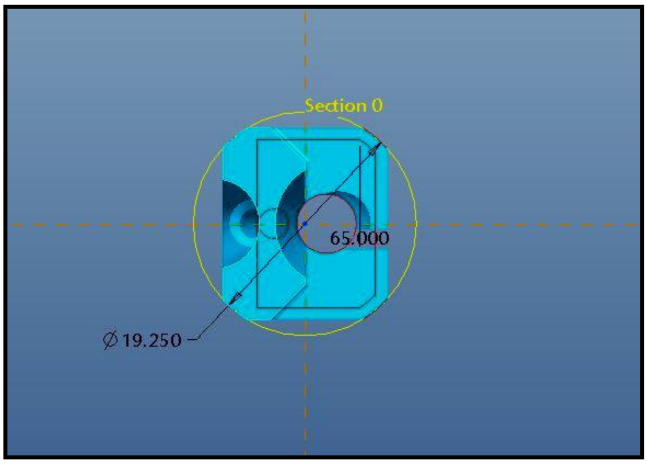


Figure 4-2 Bore selector mechanism

Figure 4-3 shows the bore selector mechanism in different view. Both the annulus and production lines are provided with chamfers so that the tool for wireline, coiled tubing are properly guided. Further, this assists in performing the operation under heave motions of the rig.

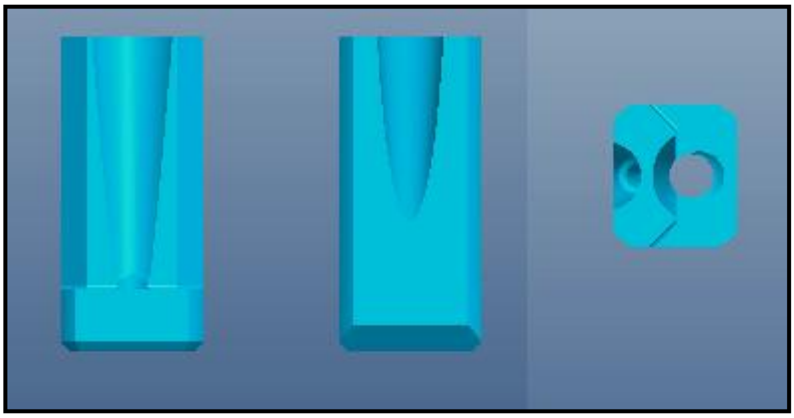


Figure 4-3 Front, back and top view of the bore selector mechanism

In preferred conceptual design, bore selector is kept as part of riser stress joint assembly and is run through rotary. Hence the design has taken care of the size limitations (diameter) of the bore selector; preventing the size becoming too large so that it can obstruct the passage through bore selector. The bore selector mechanism will be placed inside the housing; the supports being two rods from either end with flexibility for the mechanism to have an angular turn. This acts like a pivot to provide the angular turn. This angular turn helps in accessing the annulus bore (*Figure 4-5*) whereas in the other position, production bore is accessible (*Figure 4-4*). The rods fitted should be pressure containing and hence shall have metal to metal seals. This has to be discussed well in the detail design part.

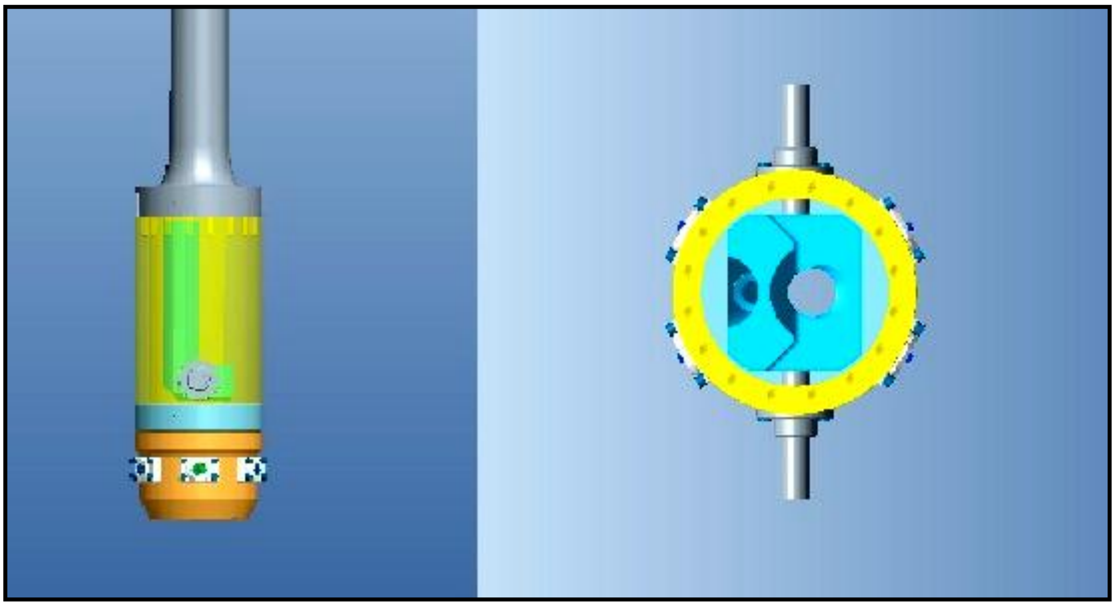


Figure 4-4 Production bore access by the bore selector

The angular movement will be provided with the help of a pivot fixed on the bore selector housing. The pivot is basically two metal rods which supports and can turn the bore selector mechanism. The rods extends outside the housing and an indicator mechanism can be provided on this rod (not shown in figures). The interfaces between rod and housing must be provided with metal to metal seal to make it pressure containing.

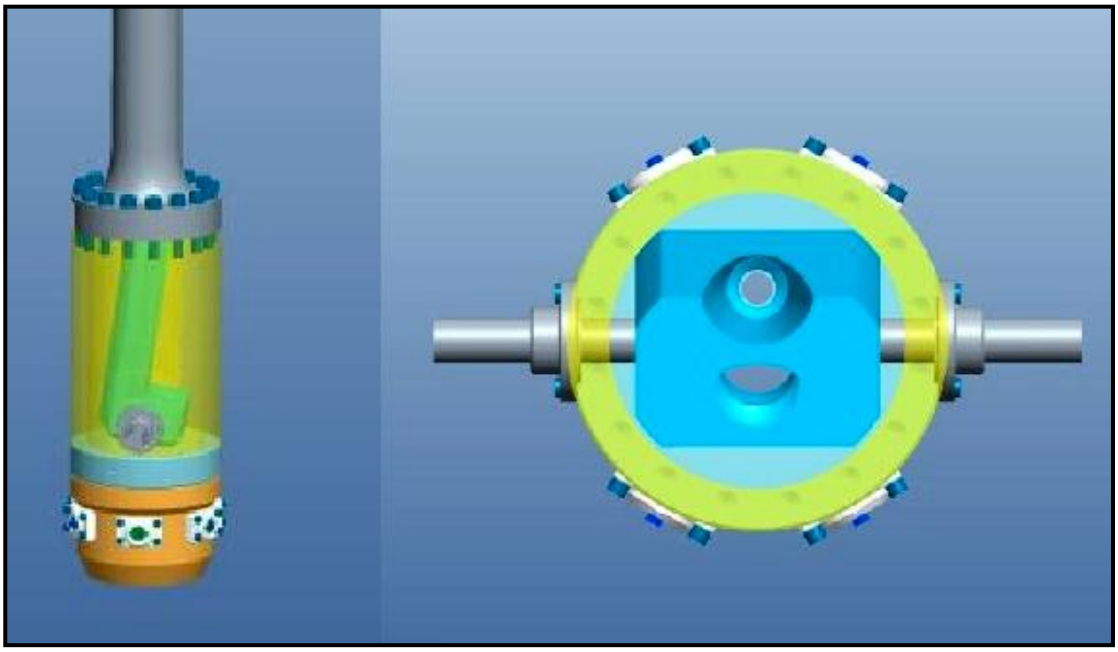


Figure 4-5 Annulus access of the bore selector

4.2 MATERIAL SELECTION FOR THE PREFERED CONCEPT

ISO 13628 -7 states that

"Materials to be selected for C/WO riser systems shall be suitable for such application during the design life unless replacement is foreseen. Due consideration shall be given to external and internal fluids, loads, temperature and possible failure modes during all phases including operation, fabrication and testing. The selection of materials shall ensure compatibility of all components in the riser system."

Before the selection and qualification of the material, it is essential to define, evaluate and document the service conditions to which the material is exposed to for each application. This is a part of customer requirement for the selection of materials. The defined conditions shall include both intended and unintended exposures which can result from the failure of primary protection methods. Cracking caused by H_2S deserves significant attention in this respect.

See *Appendix D Table 7-3* from ISO 10423 which helps in the selection of material. The table provides information on material designation with yield and tensile values. But since bore selector is an addition to the existing workover system, it is easier to select a material which has been used in other parts of the T/V workover system. Material specification report of the stress joint was checked to find out the material used in the main body of the stress joint. On investigation, it was found that low carbon steel having an yield value of 80,000 psi and 100,000 psi ultimate tensile strength is used. The material should be able to cope with external sea water and internal well fluid which are the environmental requirements.

The selected material is **8630 Modified Low Alloy Steel** based on ISO 10423, API 6A and API 17 D service. Also this alloy satisfies NACE MR0175 (Materials for use in H_2S-containing environments in oil and gas production) for sour service. To ensure materials are not susceptible to sulphide and/or stress corrosion cracking National Association of Corrosion Engineers (NACE) has developed the material requirements set out in NACE MR-0175. For sour service conditions with H_2S content exceeding the minimum specified by NACE MR-0175 (ISO 15156), $pH_2S > 0.05$ psi, at the design pressure shall per ISO 13628-7 comply with the requirements of NACE.

The design limitations for carbon and low alloy steel as per ISO 13628-1 include:

- The ratio of yield to tensile strength should not exceed 0.92
- Hydrogen Induced Stress Cracking (HISC) – Atomic hydrogen will be formed on the metal surface due to cathodic protection. These hydrogen atoms when captivated in the metal matrix can interact with the microstructure of parts subjected to high stresses, causing initiation and propagation of hydrogen related cracks known as hydrogen induced stress cracking.

- Sour service conditions possess a serious threat to completions and workover system, especially when the components are exposed to reservoir fluids during their entire life period.

The design criteria for calculation in ISO 13628-7 will take care of the first point. The ratio is 0.8 in the selected material. The second and third point is considered while selecting the material and ensuring that material does not undergo HISC and can handle sour service.

4.3 Design calculation for the preferred concept

Wall Thickness as per API 6A

API 6A provides the following information on allowable stresses using the ASME method. The allowable stresses are based on whether the bore selector housing is made from standard $(36K, 45K, 60K, and\ 75K)$ materials or from non standard high strength materials. Refer *Table 7-4* for standard material values.

For standard materials, the design stress intensity Sm is 2/3 of the yield strength, σy. For non standard materials, Sm is lower of 2/3 σy or 1/2 σu.

The maximum allowable general primary membrane stress intensity at test pressure, St is 0.83 σy for standard materials. For non-standard materials, it is the lower of 5/6 σy or 2/3 σu.

For the calculation of minimum wall thickness, associate calculations with general primary stress intensity and the test pressure. The test pressure is considered for the calculation since the bore selector designed has to undergo a testing under a pressure which is 1.5 times the design pressure. Hence our calculation will be based on the test pressure since this will probably be the maximum pressure that bore selector has to withstand during the course of life.

The equation governing the calculation of the thickness is given below:

$$tn = \frac{Pt \times R}{St - 0.5Pt}$$

where, tn is the nominal wall thickness,
Pt is the test pressure,
R is the inner radius of the bore selector housing,
St is the maximum allowable general primary membrane stress intensity at test pressure.

Taking the yield and tensile strength values for modified 8630 low alloy steel,

Yield strength, $\sigma y = 80{,}000\ psi = 551\ MPa$
Ultimate tensile strength, $\sigma u = 100{,}000\ psi = 689\ MPa$
Rated pressure $= 10{,}000\ psi = 69\ MPa$

Test pressure $Pt = 15{,}000\, psi = 103.5\, MPa$ (as per ISO 13628-7 Section 8.3.2)

Taking the rule for non standard materials, the maximum allowable general primary membrane stress intensity is the lower of 5/6 σy or 2/3 σu. Here in this case 5/6 of σy is lower than 2/3 of σu.

$$St = 0.83 \times 551 = 457\, MPa$$

Fixing the inner diameter, $Di = 508mm$ (20")

$$tn = \frac{103.5 \times 254}{457 - (0.5 \times 103.5)} = 64.87mm(2.55")$$

Hence the outer diameter of the bore selector housing, $Do = Di + 2t = 637.74mm$ (25.1").

Refer *Figure 4-6* with the calculated dimensions.

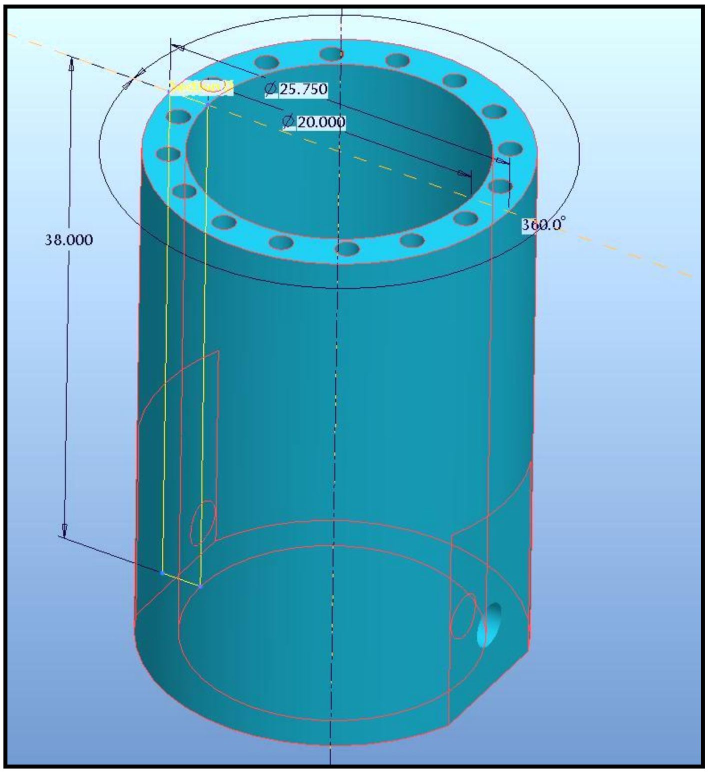


Figure 4-6 Bore Selector housing with dimensions

CAPACITY VERIFICATION

As mentioned before, the preliminary stress values for the bore selector housing are taken from the production bore pipe values of the stress joint. In this section, the values used are checked for their capacity verification to ensure that they are acceptable with respect to the industry standards. The yield stress and ultimate strength values used are checked for sufficient structural capacity to meet the requirements of API 6A for the applied test pressure. The maximum equivalent stress criterion given in API 6A section 4.3.3.3 is used. Additionally, they are checked against criteria given in ISO 13628-7.

Yield strength, $\sigma y = 80{,}000\, psi = 551\, MPa$
Ultimate tensile strength, $\sigma u = 100{,}000\, psi = 689$ MPa
Rated pressure $= 10{,}000\, psi = 69\, MPa$
Test pressure $Pt = 15{,}000\, psi = 103.5\, MPa$
Outside diameter, $Do = 637.74mm$
Inside diameter, $Di = 508mm$
Wall thickness, $tn = 64.87mm$

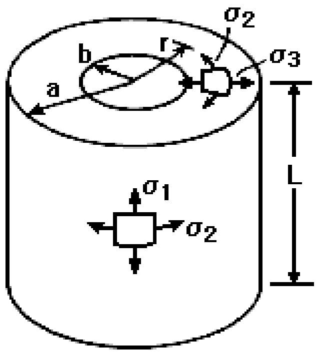
Considering bore selector housing as a cylindrical disk or shell with uniform internal pressure in all directions and ends capped

Outer radius,

$$a = \frac{Do}{2} = 318.87mm$$

Inner radius,

$$b = \frac{Di}{2} = 254\, mm$$



Length as obtained from *Figure 4-6*, $L = 38" = 965\, mm$
Internal pressure, $q = Pt = 103.5\, MPa$
Modulus of elasticity $E = 205\, GPa$
Poisson's ratio $v = 0.3$

Capacity Verification as per API 6A

Formulas for change in outer and inner radii, and change in length:

Outer radius,

$$\Delta a = \frac{q \times a}{E} \times \frac{b^2 \times (2 - v)}{(a^2 - b^2)} = \frac{103.5 \times 318.87}{205 \times 10^3} \times \frac{254^2 \times (2 - 0.3)}{(318.87^2 - 254^2)} = 0.49\, mm$$

Inner radius,

$$\Delta b = \frac{q \times b}{E} \times \frac{[a^2 \times (1 + v) + b^2 \times (1 - 2v)]}{(a^2 - b^2)}$$
$$= \frac{103.5 \times 254}{205 \times 10^3} \times \frac{[318.87^2 \times (1 + 0.3) + 254^2(1 - 2 \times 0.3)]}{(318.87^2 - 254^2)} = 0.46\, mm$$

Length,

$$\Delta L = \frac{q \times L}{E} \times \frac{b^2 \times (1 - 2v)}{(a^2 - b^2)} = \frac{103.5 \times 965}{205 \times 10^3} \times \frac{254^2 \times (1 - 2 \times 0.3)}{(318.87^2 - 254^2)} = 0.34\, mm$$

Normal stresses as a function of radial thickness, r

Longitudinal Stress,

$$\sigma 1(r) = \frac{q \times b^2}{(a^2 - b^2)}$$

Maximum Longitudinal Stress,

$$\sigma 1(b) = \frac{q \times b^2}{(a^2 - b^2)} = \frac{103.5 \times 254^2}{(318.87^2 - 254^2)} = 179.68\ MPa$$

Circumferential Stress,

$$\sigma 2(r) = \frac{q \times b^2\ (a^2 + r^2)}{r^2 \times (a^2 - b^2)}$$

Maximum Circumferential Stress at inside of wall,

$$\sigma 2(b) = \frac{q \times (a^2 + b^2)}{(a^2 - b^2)} = \frac{103.5 \times (318.87^2 + 254^2)}{(318.87^2 - 254^2)} = 462.8\ MPa$$

Radial Stress,

$$\sigma 3(r) = -\frac{q \times b^2 \times (a^2 - r^2)}{r^2 (a^2 - b^2)}$$

Maximum Radial Stress at inside of wall,

$$\sigma 3(b) = -q = -103.5\ MPa$$

Maximum shear stress (at inner radius, r=b)

$$\tau max = \frac{\sigma 2(b) - \sigma 3(b)}{2} = 283.15\ MPa$$

Von Misses equivalent stress,

$$\sigma e(r) = \sqrt{\left(\sigma 1(r)^2 + \sigma 2(r)^2 + \sigma 3(r)^2 - \left(\sigma 1(r) \times \sigma 2(r)\right) - \left(\sigma 2(r) \times \sigma 3(r)\right) - \left(\sigma 3(r) \times \sigma 1(r)\right)\right)}$$

Maximum equivalent stress, at inner surface,

$$\sigma e(b) = \sqrt{(179.68^2 + 462.8^2 + 103.5^2 - 178.68 \times 462.8 + 462.8 \times 103.5 + 103.5 \times 179.68)}$$

$$\boldsymbol{\sigma e(b) = 490.43 MPa}$$

Based on the design criteria given in API 6A, the minimum specified material yield strength shall be equal or higher than the maximum equivalent stress found. Hence minimum yield strength of 490 MPa is required. The design minimum yield strength is 551 MPa. Hence yield strength value used for the bore selector housing is acceptable.

Capacity Verification as per ISO 13628-7

Pipe burst design factor, $Fb = 0.9$
Minimum required wall thickness,

$$t1 = \frac{Do}{1 + [\frac{1.1 \times Fb \times (\sigma y + \sigma u)}{Pt}]} = \frac{637.74}{1 + [\frac{1.1 \times 0.9 \times (551 + 689)}{103.5}]} = 49.6mm$$

Wall thickness calculated is $64.87mm$
Hence safety factor

$$SF = \frac{tn}{t1} = \frac{64.87}{49.6} = 1.31$$

The safety factor as well as the wall thickness is acceptable by both the standards.

PRESSURE DESIGN CALCULATIONS

$\sigma y = 80{,}000\, psi = 551\, MPa$
$\sigma u = 100{,}000\, psi = 689\, MPa$
Modulus of elasticity $E = 205\, GPa$
Poisson's ratio $\nu = 0.3$
Nominal pipe outside diameter, $Do = 637.74mm$
Nominal pipe inside diameter, $Di = 508mm$
Nominal Wall thickness, $tn = 64.87mm$
Corrosion allowance on wall thickness, $tca = 1.3mm$

Load Conditions

All the equations are referred to **ISO 13628-7**(Design and operation of subsea production systems-Completion/workover systems)

Hydro test conditions

Riser External test pressure, $Podhyd = 0$
Riser Internal test pressure, $Pidhyd = 103.5\, MPa\ (1.5\ X\ Design\ pressure)$

Operating conditions

Load condition and design factors is taken from ISO 13628-7. Refer *Appendix* B *Table 7-6* for the same table.

The discussions are based on 3 different scenarios viz. Normal operation, extreme operation and accidental case. The design factors for these conditions are as mentioned below:

Normal operation, $\boldsymbol{Fd = 0.67}$

Extreme Operation, $\boldsymbol{Fd = 0.80}$

Accidental, $\boldsymbol{Fd = 1.00}$

Pressure design calculation for design factor, Fd = 1

Maximum riser external operating pressure at maximum operating depth 300m, $Podop = 3.02\ MPa$
Minimum Riser external pressure at surface, $Podsu = 0$
Riser internal operating pressure, $Pidop = 69MPa$

Pressure Design as per Section 6.5.2.1 of ISO 13628-7

The data initially required for sizing the bore selector are

- Internal diameter with pipe ovality, wall thickness tolerance and corrosion allowance;
- Design material strength and Young's modulus;
- Internal and external design pressure.

This will help to obtain preliminary size of housing in which the bore selector mechanism will be accommodated.

As per ISO 13628-7

"The wall thickness can initially be determined to guarantee

- Containment of the maximum net internal pressure (bursting);
- Adequate strength against net external pressure, simple hoop buckling."

The initial sizes obtained in this part should be refined enough so that only minor modifications are required in the detailed design and analysis phase. An optimum value of housing will be generated only by several iterations.

As per API specification 5L [4], a maximum negative tolerance of -12.5% is considered for a pipe diameter less than 20 inches and for diameters greater than 20 inches a negative tolerance of -8.0% is adopted. However, with the advent of new technologies, it is now possible to manufacture pipe with tolerance less than the above specified values. Hence a negative tolerance value of -5% of the nominal wall thickness is taken here for the calculations.

Mill tolerance on wall thickness $tfab = 3.2\ mm$

Corrosion allowance on wall thickness, $tca = 1.3mm$

Minimum Wall thickness in fabricated condition $t1hyd = tn - tfab = 61.67\ mm$

Minimum Wall thickness in operating condition, $t1op = tn - tfab - tca = 60.37\ mm$

Internal Pressure (burst design) as per Section 6.5.2.2 of ISO 13628-7

$Rt0{,}5$ is the specified minimum yield strength for 0,5 % total elongation at room temperature=σy

Ductility factor for materials with elongation > 14%, $\phi A5 = 1$

Temperature reduction factor yield strength Yy at 121°C= 0.91 as per *Table 7-2*
Temperature reduction factor ultimate tensile strength Yu at 121°C = 1.0 as per *Table 7-2*

Pressure Containment design factors for internal design pressure, $Fbhyd = 0.9$ as per *Table 7-7*
Pressure Containment design factors for hydrostatic test pressure, $Fbop = 0.6$ as per *Table 7-7*

Yield strength in fabricated condition,

$$\sigma yhyd = \phi A5. min(R05, 0.92X\sigma u) = 551MPa$$

(No temperature reduction factor is provided since bore selector housing is not subjected to elevated temperature during hydrostatic pressure test. Refer Section 6.4.6)

Yield strength in operating condition

$$\sigma yop = \phi A5. Yy. min(R05, 0.92. \sigma u) = 502\ MPa$$

Minimum Ultimate Tensile Strength (UTS) at room temperature, $Rm = 689\ MPa$
Ultimate Tensile strength in fabricated condition, $\sigma uhyd = \phi A5. Rm = 689\ MPa$

(No temperature reduction factor is provided since bore selector housing is not subjected to elevated temperature during hydrostatic pressure test. Refer Section 6.4.6)

Ultimate Tensile strength in operating condition $\sigma uop = \emptyset A5 \times Yu \times Rm$ = 689 MPa

Minimum burst pressure for hydrostatic test,

$$Pb\,\text{hyd} = 1.1 \times (\sigma yhyd + \sigma uhyd) \times \frac{t1hyd}{Do - t1hyd}$$
$$= 1.1 \times (551 + 689) \times \frac{61.67}{637.74 - 61.67} = 146\ MPa$$

Minimum burst pressure for internal pressure design,

$$Pb,\text{op} = 1.1 \times (\sigma yop + \sigma uop) \times \frac{t1op}{Do - t1op} = 1.1 \times (502 + 689) \times \frac{60.37}{637.74 - 60.37}$$
$$= 137\ MPa$$

The minimum burst pressure of the pipe at hydrostatic testing after 5 years of service and corrosion allowance taken into account for recertification

$$Pb,\text{recert} = 1.1 \times (\sigma yhyd + \sigma uhyd) \times \frac{t1op}{Do - t1op}$$
$$= 1.1 \times (551 + 689) \times \frac{60.37}{637.74 - 60.37} = 143\ MPa$$

Interaction ratio for pipe burst at hydro testing,

$$Pinterid = \frac{(Pidhyd - Podhyd)}{Fbhyd \times Pbhyd} = 0.79$$

Acceptance criteria is less than 1

Interaction ratio for pipe burst at hydro testing,

$$Pinterop = \frac{(Pidop - Podsu)}{Fbop \times Pbop} = 0.84$$

Acceptance criteria is less than 1

Interaction ratio for pipe burst at hydro testing for recertification purpose,

$$Pinterrecert = \frac{(Pidhyd - Podhyd)}{Fbhyd \times Pbrecert} = 0.80$$

Acceptance criteria is less than 1

External pressure (Hoop buckling Design) as per Section 6.5.2.3 of ISO 13628-7

To meet the external pressure design as defined by,

$$\frac{(Podhb - Pidhb\ )}{Fhb \times Pcmin} \leq 1$$

where, $Podhb$ is the maximum external design pressure at 300 m water depth = $3.02\ MPa$
$Pidhb$ is the minimum hydrostatic internal pressure = 0

Fhb is the pipe hoop buckling (collapse) design factor, obtained from *Table 7-7* =0.67
Pc, min is the minimum pipe hoop buckling (collapse) pressure(MPa)

The step to calculate $Pcmin$ follows:

Minimum elastic hoop buckling (collapse) pressure (instability) of pipe cross-section

$$Pel, \min = \left(2 \times E \times \frac{(\frac{t1op}{Do - t1op})^3}{1 - v^2} \right) = 2 \times 205 \times 10^3 \times \frac{\left(\frac{60.37}{637.74 - 60.37}\right)^3}{1 - 0.3^2}$$
$$= 515\ MPa$$

Minimum plastic pressure at collapse of pipe cross-section,

$$Pp, \min = 2 \times \sigma yop \times \frac{t1op}{Do} = 2 \times 502 \times \frac{60.37}{637.74} = 95\ MPa$$

Worst ovality = 0.015 (Maximum = 1.5% and minimum = 0.25% as per Section 6.5.2.3)

The minimum hoop buckling (collapse) pressure, $Pcmin$, shall be calculated as

$$(Pcmin - Pelmin) \times (Pcmin^2 - Ppmin^2) - \left[Pc\min \times Pel\min \times Pp\ min \times 2 \times fo \times \frac{Do}{t1op}\right] = 0$$

$$(Pcmin - 515) \times (Pcmin^2 - 95^2) - \left[Pc\min \times 515 \times 95 \times 2 \times 0.015 \times \frac{637.74}{60.37}\right] = 0$$

Solving the equation gives,

$$Pcmin = 87\ MPa$$

Applying the values,

External Pressure design,

$$Hinterhyd = \frac{(Podhb - Pidhb)}{Fhb \times Pcmin} = \frac{(3.02)}{0.67 \times 87} = 0.052$$

Acceptance criteria is less than 1

Combined load design as per Section 6.5.3 of ISO 13628-7

The thickness for pipe used in combined load effect checks shall be the nominal thickness minus corrosion allowance given by Equation

$$t2 = tn - tca$$

where,

$t2$ is the pipe wall thickness without allowances(mm);
tn is the nominal (specified) pipe wall thickness(mm);
tca is the corrosion/wear/erosion allowance(mm).

$$t2 = 63.57\ mm$$

Net internal overpressure is given by,

$$\left[\frac{Te}{Fd \times Tpc}\right]^2 + \frac{|Mbm|}{Fd \times Mpc}\ X \sqrt{1 - \left(\frac{Pidop - Podsu}{Fd \times Pb}\right)^2} + \left(\frac{Pidop - Podsu}{Fd \times Pb}\right)^2 \leq 1$$

where,
Te is the effective tension in the pipe(MN);
Tpc is the plastic tension capacity of the pipe(MN);
Fd is the design factor;
Mbm is the bending moment in the pipe(MNm);;
Mpc is the plastic bending moment capacity of the pipe(MNm);
$Podsu$ is the external pressure(MPa);
$Pidop$ is the internal pressure in the pipe(MPa);
$Pcmin$ is the pipe hoop buckling (collapse) pressure(MPa).

Plastic bending moment capacity of pipe,

$$Mpc = \propto bm \times \sigma yop \times \frac{1}{6}\left[Do^3 - (Do - 2 \times t2)^3\right]$$

where, αbm is the pipe cross-section slenderness parameter;
Do is the specified or nominal pipe outside diameter(mm);
$t2$ is the pipe wall thickness without allowances(mm)

$$Mpc = 1 \times 502 \times \frac{1}{6}\left[637.74^3 - (637.74 - 2 \times 63.57)^3\right] = 10.56\ MNm$$

Design factor per *Table 7-6* for working, $Fd = 0.67$

The cross sectional slenderness parameter αbm is given by equations

$$\propto bm = 1\ for\ \frac{\sigma y \times Do}{E \times t2} \leq 0.0517$$

$$\propto bm = 1.13 - 2.58 \times \frac{\sigma y \times Do}{E \times t2}\ for\ 0.0517 < \frac{\sigma y \times Do}{E \times t2} \leq 0.1034$$

$$\propto bm = 0.94 - 0.76 \times \frac{\sigma y \times Do}{E \times t2}\ for\ 0.1034 < \frac{\sigma y \times Do}{E \times t2} \leq 0.0170$$

$$\frac{\sigma y \times Do}{E \times t2} = 0.027$$

Hence $\alpha bm = 1$

Plastic tension capacity of pipe

$$Tpc = \sigma yop \times Ac = \sigma yop \times \pi \times (Do - t2) \times t2$$
$$= 502 \times \pi \times (637.74 - 63.57) \times 63.57 = 57.56\, MN$$

where
Ac is the pipe cross-section area;
σyop is the design yield strength(MPa).

Burst pressure of pipe

$$Pb\min = 1.1 \times (\sigma yop + \sigma uop) \times \frac{t2}{Do - t2} = 1.1 \times (502 + 689) \times \frac{63.57}{637.74 - 63.57}$$
$$= 145.1\, MPa$$

Finding maximum bending moment as a function of riser tension, at maximum working pressure

$$Te = Pidop \times Ai = 13.98\, MN$$

$$\left[\frac{Te}{Fd \times Tpc}\right]^2 + \left(\frac{|Mmax1|}{Fd \times Mpc} \times \sqrt{1 - \left(\frac{Pidop - Podsu}{Fd \times Pbmin}\right)^2}\right) + \left(\frac{Pidop - Podsu}{Fd \times Pbmin}\right)^2 = 1$$

$$\left[\frac{13.98}{0.67 \times 57.56}\right]^2 + \left(\frac{|Mmax|}{0.67 \times 10.56} \times \sqrt{1 - \left(\frac{69}{0.67 \times 145.1}\right)^2}\right) + \left(\frac{69}{0.67 \times 145.1}\right)^2$$
$$= 1$$

$$Mmax1 = 3.68\, MNm$$

Set $Me = 0$

$$Te = Tmax$$

$$\left[\frac{Tmax}{Fd \times Tpc}\right]^2 + \left(\frac{|Me|}{Fd \times Mpc}\, X \sqrt{1 - \left(\frac{Pint - Podsu}{Fd \times Pb}\right)^2}\right) + \left(\frac{Pidop - Podsu}{Fd \times Pbmin}\right)^2 = 1$$

$$\left[\frac{Tmax}{0.67 \times 57.56}\right]^2 + \left(\frac{69}{0.67 \times 145.1}\right)^2 = 1$$

$$Tmax = 27.27\ MN$$

$$Tmax1 = Tmax - Pidop\,.Ai - Podsu.Ao = 13.29\ MN$$

Net External overpressure Section 6.5.3.3 of ISO 13628-7

To meet net external overpressure design criteria,

$$\left[\left(\frac{Te}{Fd\ \times Tpc}\right)^2 + \left(\frac{Mbm}{0.95 \times Fd \times Mpc}\right)\right]^2 + \left(\frac{Podop - Pint}{Fd \times Pcmin}\right)^2 \leq 1$$

Assume maximum external pressure at 300m, $Podop = 3.02\ MPa$
Fd as per internal combined from *Table 7-6* $Fd\ = \ 0.67$
Internal pressure to give worst case $Pint = 0$

$$(Pcmin - Pelmin) \times (Pcmin^2 - Ppmin^2) - \left[Pc\min \times Pel\min \times Pp\min \times 2\ \times fo\ \times \frac{Do}{t1op}\right] = 0$$

Minimum elastic hoop buckling (collapse) pressure (instability) of pipe cross-section

$$Pel\min = (2 \times E \times \frac{(\frac{t2}{Do - t2})^3}{1 - \ v^2} = 2 \times 205\ \times 10^3 \times \frac{\left(\frac{63.57}{637.74 - 63.57}\right)^3}{1 - 0.3^2} = 611.47\ MPa$$

Minimum plastic pressure at collapse of pipe cross-section

$$Pp\min = 2 \times \sigma yop\ \times \frac{t2}{Do} = 2 \times 502\ \times \frac{63.57}{637.74} = 100\ MPa$$

The hoop buckling pressure,

$$(Pcmin - Pelmin) \times (Pcmin^2 - Ppmin^2) - \left[Pc\min \times Pel\min \times Pp\min \times 2\ \times fo\ \times \frac{Do}{t1op}\right] = 0$$

$$(Pcmin - 611.47) \times (Pcmin^2 - 100^2) - \left[Pc\min \times 611.47 \times 100\ \times 2\ \times 0.015\ \times \frac{637.74}{63.57}\right] = 0$$

$$Pcmin = 84\ MPa$$

Find maximum bending moment as a function of riser tension, pressure end load from max working pressure

$$\left[\left(\frac{Te}{Fd\ \times Tpc}\right)^2 + \left(\frac{Mbm}{0.95 \times Fd \times Mpc}\right)\right]^2 + \left(\frac{Podop - Pint}{Fd \times Pcmin}\right)^2 = 1$$

$$\left[\left(\frac{13.98}{0.67 \times 57.56}\right)^2 + \left(\frac{Mbm}{0.95 \times 0.67 \times 10.56}\right)\right]^2 + \left(\frac{3.02}{0.67 \times 84}\right)^2 = 1$$

$$Mmax2 = 5.83MNm$$

Given

$$Te = Tmax$$

$$Me = 0$$

$$\left[\left(\frac{Tmax}{Fd \ \times Tpc}\right)^2 + \left(\frac{Me}{0.95 \times Fd \times Mpc}\right)\right]^2 + \left(\frac{Podop - Pint}{Fd \times Pcmin}\right)^2 = 1$$

$$\left[\left(\frac{Tmax}{0.67 \ \times 57.56}\right)^2\right]^2 + \left(\frac{3.02}{0.67 \times 84}\right)^2 = 1$$

$$Tmax = 38.54MN$$

$$Tmax2 = Tmax - Te = 24.56 \ MN$$

Find max bending and tension combined loads net internal and external over pressure

At Maximum Working Pressure:

$$Tmax \ = \ min(Tmax1, Tmax2) \ MN \ = \ min(13.29, 24.56) \ MN$$

$$Mmax = \ min(Mmax1, Mmax2) \ MNm = \ min(3.68, 5.83) \ MNm$$

$$\boxed{\begin{aligned} \boldsymbol{Tmax} &= \boldsymbol{13.29 \ MN} \\ \boldsymbol{Mmax} &= \boldsymbol{3.68 \ MNm} \end{aligned}}$$

Summary of results:

Calculation Summary

All ratio has to be equal or less than 1.

Internal hydro test, $Pinterid \ = \ 0.79$
Internal operating test, $Pinterop \ = \ 0.84$
Internal hydro test for recertification, $Pinterrecert \ = \ 0.80$
External collapse, $Hinterhyd \ = \ 0.052$

Maximum capacities at MWP:

ISO Tensile Capacity, Tmax = 13.29 MN at zero bending.
ISO Bending Capacity, Mmax = 3.68 MNm at zero tension.

The values obtained above are for normal operating condition with a design factor of 0.67.Similar calculations are performed for Extreme (Fd=0.8) and Accidental (Fd=1.0) conditions. Refer *Appendix D* for the calculations. All the ratio obtained are within acceptable limits. The bending and tensile capacities has been found out in each case. The summary of calculations are taken and tabulated below :

Table 4-1 Tensile capacity for three different operating conditions

	Normal(Fd=0.67)	Extreme(Fd=0.8)	Accidental(Fd=1)
Tensile Capacity at 10,000psi(69MPa) internal pressure (MN)	13.29	23	36.66

Table 4-2 Bending capacity for three different operating conditions

	Normal(Fd=0.67)	Extreme(Fd=0.8)	Accidental(Fd=1)
Bending Capacity at 10,000psi (69 MPa) internal pressure(MNm)	3.68	5.87	8.57

The tensile and bending capacity values as mentioned in *Table 4-1* and *Table 4-2* are used in the next stage of design calculations. These calculations are used to cross check the flange strength. Currently, the already existing flange at the end of the stress joint which will be interfacing with the bore selector housing. This flange has to be checked against its capacity to ensure that the number of bolts and its diameter using the values obtained above.

5 CONCLUSION

Workover operations are of utmost importance especially, in these days with ageing fields and declining production. Operators are considering cheaper ways to intervene the wells with improved efficiency and reduced time. The thesis is aimed at designing a bore selector which helps to eliminate the requirement of annulus line in Tordis Vigdis workover system. The induction of bore selector into the workover system lowers the operating time in running the workover risers, and reduces the overall weight of the workover riser system, which makes it easier to handle.

The thesis discusses the general procedure involved in designing a bore selector. The report discussed different options of positioning the bore selector with the advantages and disadvantages in each location on the workover system. The best position was determined, and conceptual models were drawn. The output of the thesis is the development of the preferred concept of a bore selector with drawings and associated calculations. This has been developed out of the four different concepts discussed. 'Microsoft Visio 2007' and Drawing tool 'Creo Element/Pro Version 5' are the drawing tools used to create drawings. The layout was made with exact dimensions to match the Tordis Vigdis workover system. The layout is made by fixing the internal diameter and determining the outside diameter and wall thickness of the bore selector housing by API standards. Capacity verification with respect to API and ISO standards has been performed to check that the selected thickness, yield and ultimate strength values are suitable for the selected design. This proved to be acceptable with respect to verification performed, and safety factor for the design was obtained.

Pressure design calculations were also performed for the concept. The pressure design calculations included internal pressure design (burst design), external pressure design (hoop buckling design) and combined load design. This calculation helps to find the bending moment and tension at maximum working pressure. The model was analysed for internal pressure hydro test, internal pressure operating test, internal pressure hydro test for recertification and external collapse. This has been performed for normal operating condition, extreme operating condition and accidental operating condition with design factors of 0.67, 0.8 and 1.0 respectively. All the ratios obtained are within the acceptable range with respect to the calculations performed and can be considered as a positive sign in moving forward with the design.

With tensile and bending moment values calculated, the design can be further considered for load calculation for the flange design. Currently, the flange at the bottom of the stress joint is used as interface connecting the stress joint to bore selector housing. This flange capacity has to be calculated to determine the number of bolts and the bolt diameter. This has to be performed in the next stage of design.

Eventually, past few months has been immensely informative and educative period in understanding and gaining in depth knowledge about workover system and also in learning the basic concepts of design.

5.1 FUTURE WORK

Referring to the design flow chart (*Figure 1-2*), it can be understood that the thesis has covered only upto design calculations for the preferred concept which includes wall thickness, bending moment and tensile strength calculations of the bore selector housing. This is due to time constraints in finishing the tasks. The detailed design, manufacturing of a prototype and product qualification are yet to be done to release bore selector in the market. In the drawings, the secondary back up mechanism for the bore selector is not designed eventhough it is design requirement. Hydraulic motor with hydraulic supply from workover control system can be considered as a possible option. Another viewpoint on this would be making the hydraulic mechanism, the preliminary mode of control with mechanical way of rotating the pivot as the backup. Also, the flange load calculations need to be performed.

The detailed design part must include global riser analysis. The purpose of global riser system analyses is to describe the overall static and dynamic structural behaviour, by exposing the system to a stationary environmental loading condition (DNV-OSS-302, 2003). The global analysis considers the dynamic and static effects of the operating parameters like significant wave height, the cyclic wave loads, the heave motions, the wind effect etc. Besides, the design load effects must be based on global riser analysis of the riser system including environmental, functional, pressure load effects during all phases of use. The output of the analysis is the operating envelope with limiting sea states (operational window), which should be referred and used by the offshore personnel to keep the completion/workover riser within its parameters during offshore use. Further activities may include developing detailed drawing for manufacturing of the bore selector prototype. The fabricated prototype must undergo function and pressure test (test pressure is 1.5 times the design pressure). The prototype should undergo qualification tests along with preload verification, capacity testing, cyclic load test and disconnect test. Also, it is imperative to check whether the bore selector satisfies PSL (Product Specification Level) state. The bore selector can be subjected to Factory Acceptance Test (FAT) and Site Integration Test (SIT) to check the successful integration with Stress joint, RDP, LRP, VXT and the WOCS. Trial run of the bore selector along with the entire workover system at offshore can confirm the successful design of the bore selector.

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7 APPENDIX

7.1 APPENDIX A - LIST OF FACTS & FIGURES

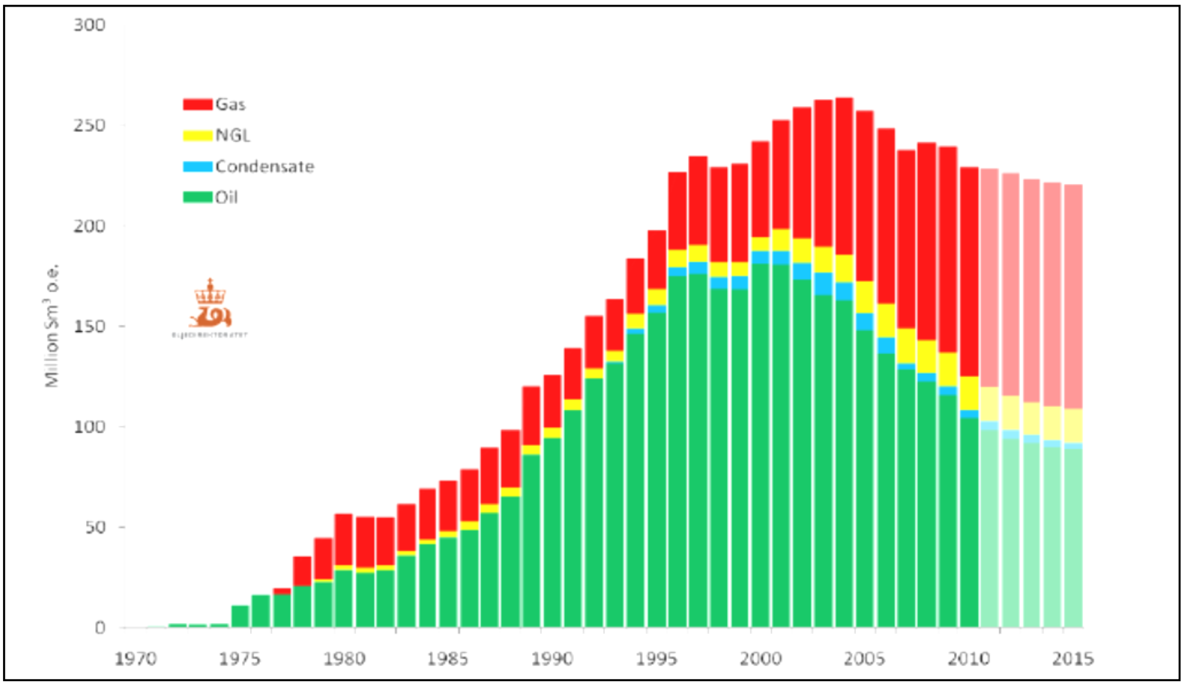

Figure 7-1 NCS petroleum history and projection (The Shelf, 2011)

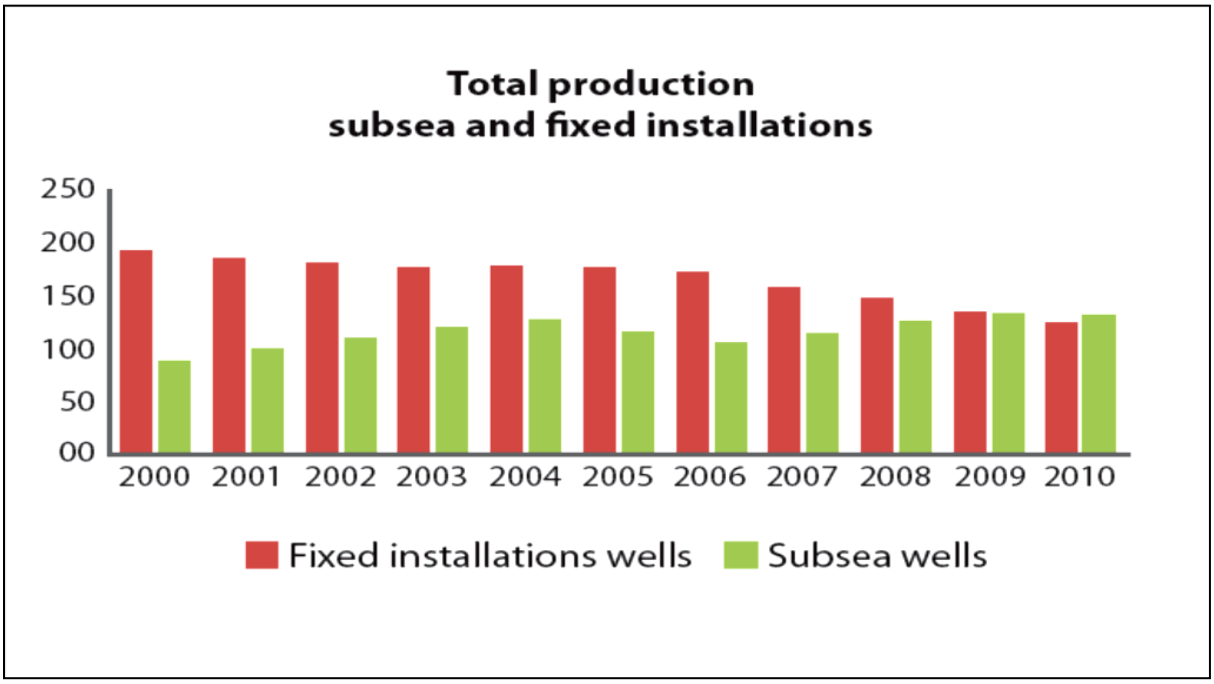

Figure 7-2 Comparison fixed installation well and subsea wells (NPD, 2011)

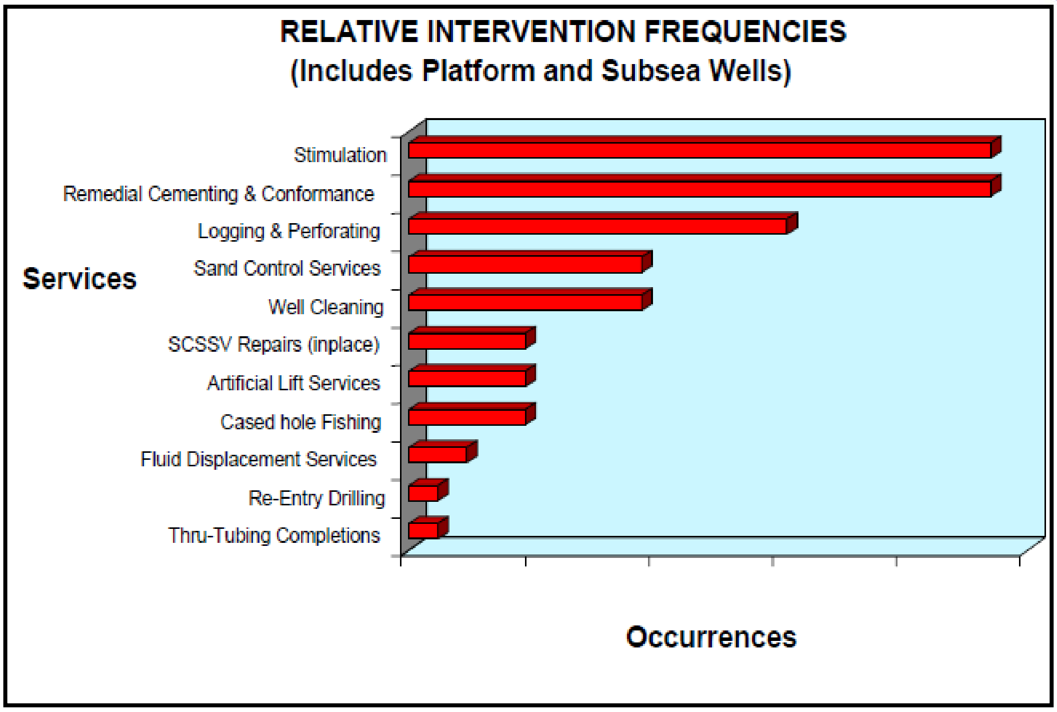

Figure 7-3 Relative intervention frequencies (Khurana S., Dewalt B. and Headworth C., 2003)

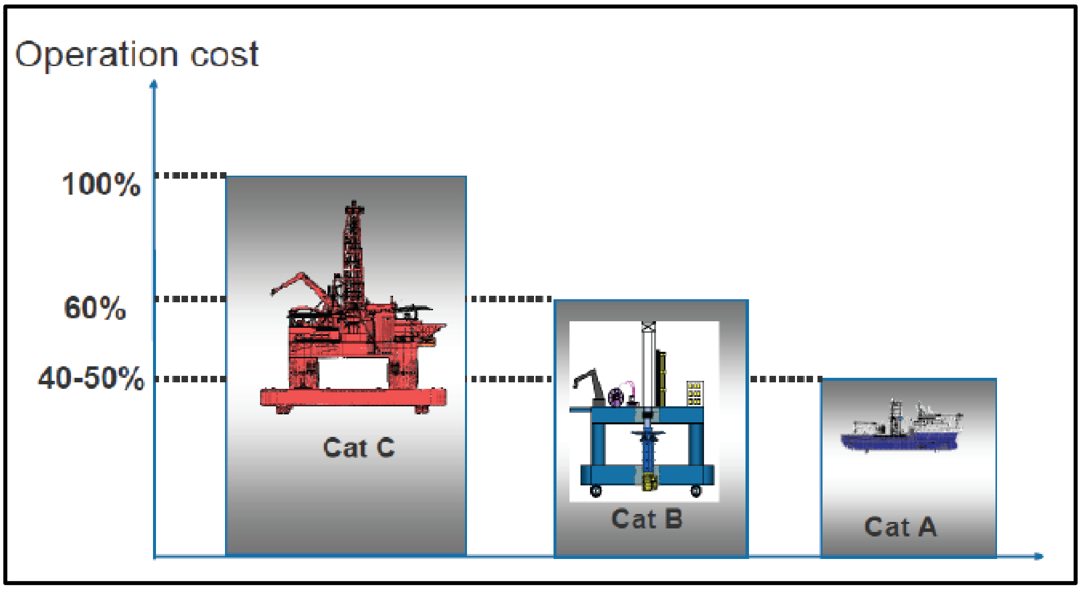

Figure 7-4 Cost comparisons of different types of intervention (Fjaertoft L. and Sonstabo G., 2011)

Components of Tordis Vigdis workover system

Figure 7-5 LRP for the T/V workover system

Figure 7-6 RDP for the T/V workover system

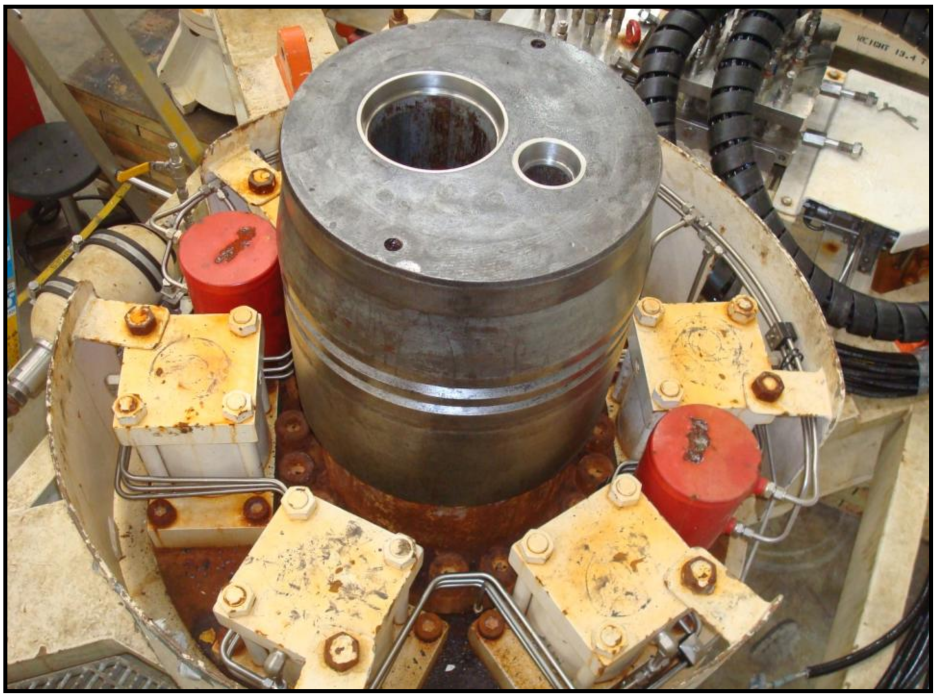
Figure 7-7 RDP interface at the top

Figure 7-8 Standard riser joint

Figure 7-9 Riser Stress joint

Figure 7-10 Cased Wear Joint

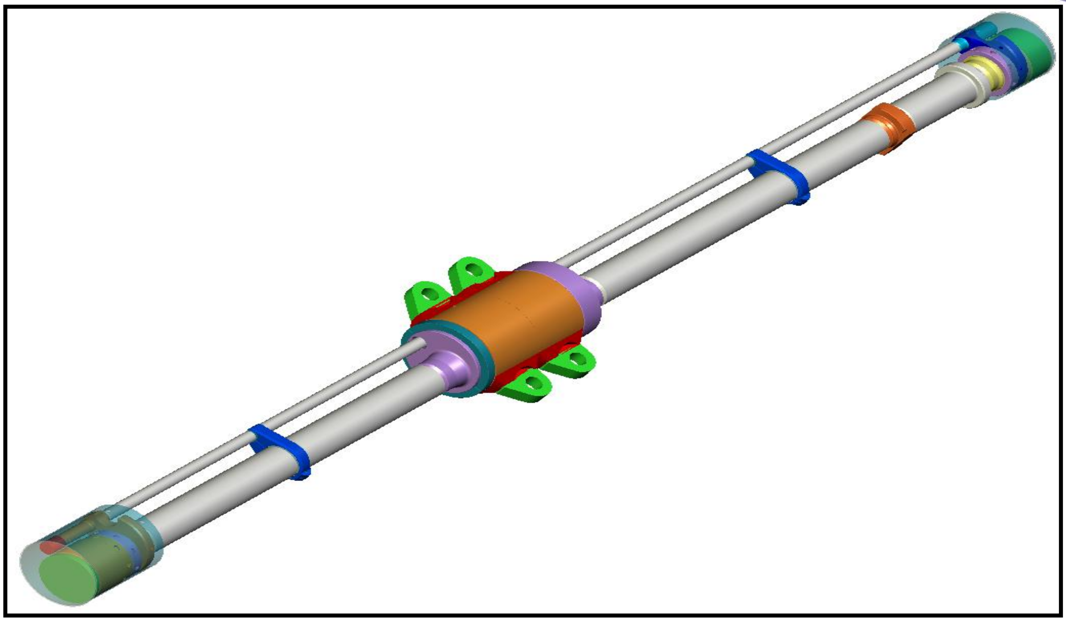

Figure 7-11 Tension Joint

Figure 7-12 View of the surface tree from underside

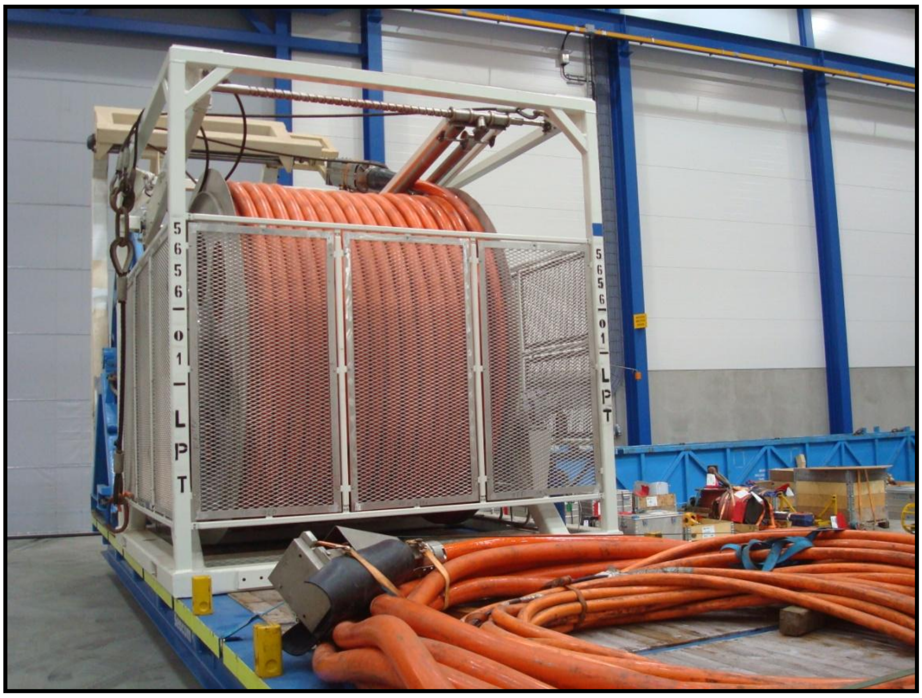

Figure 7-13 Umbilical reel for the workover control system

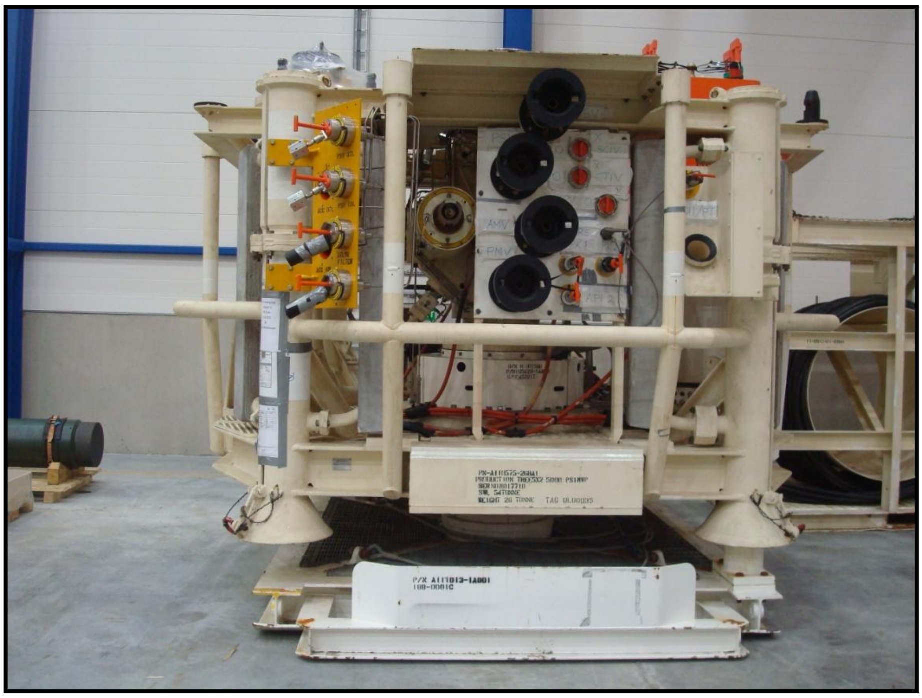

Figure 7-14 Christmas tree for the T/V field

Figure 7-15 MR Connector at the bottom of stress joint

Figure 7-16 MR Connector showing both the production and annulus bores

7.2 APPENDIX B – TABLES USED FOR CALCULATION ISO & API STANDARDS

List of tables from standards for material requirement, wall thickness and pressure design calculations

Table 7-1 Internal pressure design classes (ISO-13628, 2005)

$p_{\mathrm{int,d}}$ MPa (psi)
34,5 (5 000)
69,0 (10 000)
103,5 (15 000)
138,0 (20 000)

Table 7-2 Temperature design classes based on fluid temperature(ISO-13628, 2005)

Temperature classification	Operating range °C (°F)	
	Minimum	Maximum
K	– 60 (– 75)	82 (180)
L	– 46 (– 50)	82 (180)
P	– 29 (– 20)	82 (180)
R	Room temperature	
S	– 18 (0)	66 (150)
T	– 18 (0)	82 (180)
U	– 18 (0)	121 (250)
V	2 (35)	121 (250)
X	– 18 (0)	180 (350)
Y	– 18 (0)	345 (650)

Table 7-3 Material Requirements Table from (ISO 10423, 2009)

Material class		Minimum material requirements	
		Body, bonnet, end and outlet connections	Pressure-controlling parts, stems and mandrel hangers
AA	General service	Carbon or low-alloy steel	Carbon or low-alloy steel
BB	General service	Carbon or low-alloy steel	Stainless steel
CC	General service	Stainless steel	Stainless steel
DD	Sour service[a]	Carbon or low-alloy steel[b]	Carbon or low-alloy steel[b]
EE	Sour service[a]	Carbon or low-alloy steel[b]	Stainless steel[b]
FF	Sour service[a]	Stainless steel[b]	Stainless steel[b]
HH	Sour service[a]	CRAs[bcd]	CRAs[bcd]

a As defined by ISO 15156 (all parts) (NACE MR0175; see Clause 2).
b In accordance with ISO 15156 (all parts) (NACE MR0175; see Clause 2).
c CRA required on retained fluid-wetted surfaces only; CRA cladding of low-alloy or stainless steel is permitted [see 6.5.1.2.2 a)].
d CRA as defined in Clause 3; ISO 15156 (all parts) (NACE MR0175; see Clause 2) definition of CRA does not apply.

Table 7-4 Standard material property requirement (API 6A, 2011)

Material designation	0,2 % offset yield strength min. Mpa (psi)	Tensile strength min. Mpa (psi)	Elongation in 50 mm (2 in) min. %	Reduction in area min. %
36K	248 (36 000)	483 (70 000)	21	No requirement
45K	310 (45 000)	483 (70 000)	19	32
60K	414 (60 000)	586 (85 000)	18	35
75K	517 (75 000)	655 (95 000)	17	35

Table 7-5 Optional reduction factors for elevated temperatures of carbon manganese and low alloy steels (ISO-13628, 2005)

Temperature reduction factor	Temperature °C (°F)				
	Room temperature	66 (150)	82 (180)	121 (250)	180 (350)
Y_y	1,00	0,99	0,97	0,91	0,85
Y_u	1,00	1,00	1,00	1,00	1,00

Table 7-6 Design factors(ISO-13628, 2005)

Load condition	F_d	Failure mode calculation basis
Assembly (bolting-up or make-up) and disassembly (break-out)	0,90	Based on actual design values at assembly/disassembly temperature
Mill/FAT hydrostatic pressure test	0,90	Based on actual design values at test temperature, fluid (hydrostatic)
Normal operation	0,67	Based on corroded wall thickness at design metal temperature
Extreme operation	0,80	Based on corroded wall thickness at design metal temperature
System (in-service) pressure test	0,67	Based on corroded wall thickness at test temperature
Temporary operation	0,80	Based on corroded wall thickness at actual metal temperature
Accidental (survival)	1,00	Based on corroded wall thickness at actual metal temperature

Table 7-7 Burst (pressure containment) design factors, Fb (ISO-13628, 2005)

Internal design pressure	Hydrostatic test pressure
0,60	0,90

Table 7-8 Hoop buckling (collapse) design factor (ISO-13628, 2005)

Pipe manufacturing process	External design pressure	Hydrostatic test pressure
Seamless	0,67	0,80

7.3 APPENDIX C - OVERVIEW OF EXISTING TECHNOLOGIES

Sonsub Inc. C/WO Riser System

Sonsub Inc. has developed a completion/workover riser control system in which the bore selector concept is used. The system is to be used with a 4" × 2" tubing hanger and subsea tree and is rated for 10,000psi working pressure. The C/WO system can be used for both tree mode and tubing hanger mode. The riser system is unique concentric one with a 5" nominal pipe housed inside an 8" nominal pipe. The inner pipe acts as the flow path and provides means for wireline or coiled tubing operation. The annular area between the two pipes provides a second flow path which can be used to circulate the well or otherwise communicate with the annulus. A bore selector located in the Emergency Disconnect Package in the Tree Mode and in the BOP Spanner/Pack- Off Joint Assembly in the Tubing Hanger Mode, provides a means of vertically accessing the annulus in the tree or tubing hanger, respectively. Figure is provided to understand the whole stack up. If annulus access is not required in the tree mode, the riser can be run without the bore selector by using a lower riser adapter (Parks W.C, Smith J.D. and Weathers G.G., 1995).

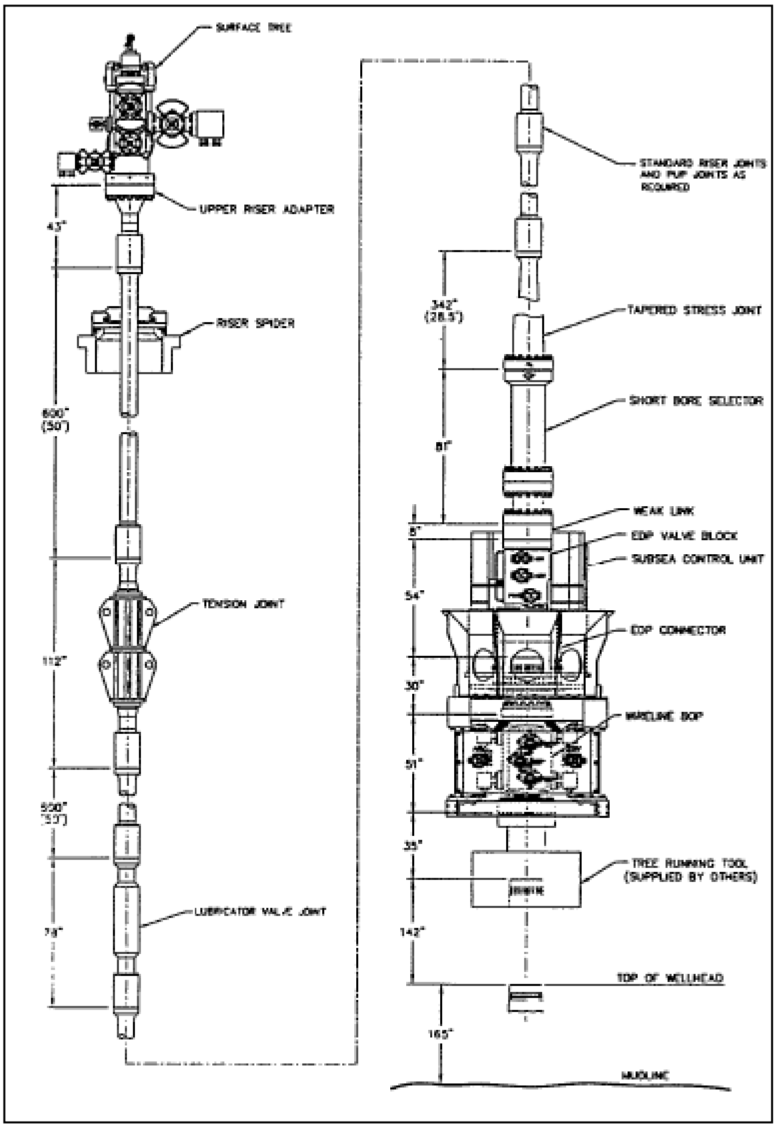

Figure 7-17 Completion/Workover riser Tree mode system stack up (Parks W.C., Smith J. D. and Weathers G.G., 1995)

The bore selector mounts to the top of the EDP valve block and provides a means of accessing either the production or annulus bores via the concentric riser. The bore selector consists of a fixed outer body and an internal housing with an elliptical bore which provides a smooth transition from the central riser bore to either the production or annulus bore. The area between the outer and inner housing provides an annular flow path for circulation. The 2“ annulus bore is normally plugged with a wireline plug to prevent wireline or coiled tubing inadvertently entering the annulus bore during wireline/coiled tubing operations in the production bore. To access the annulus bore, a whipstock (kick-over tool) is installed in the production bore to divert wireline tools into the annulus bore (Refer figure which explains the operational sequence). The tubing plug is then removed, providing full, unrestricted access into the annulus bore. (Parks W.C, Smith J.D. and Weathers G.G., 1995).

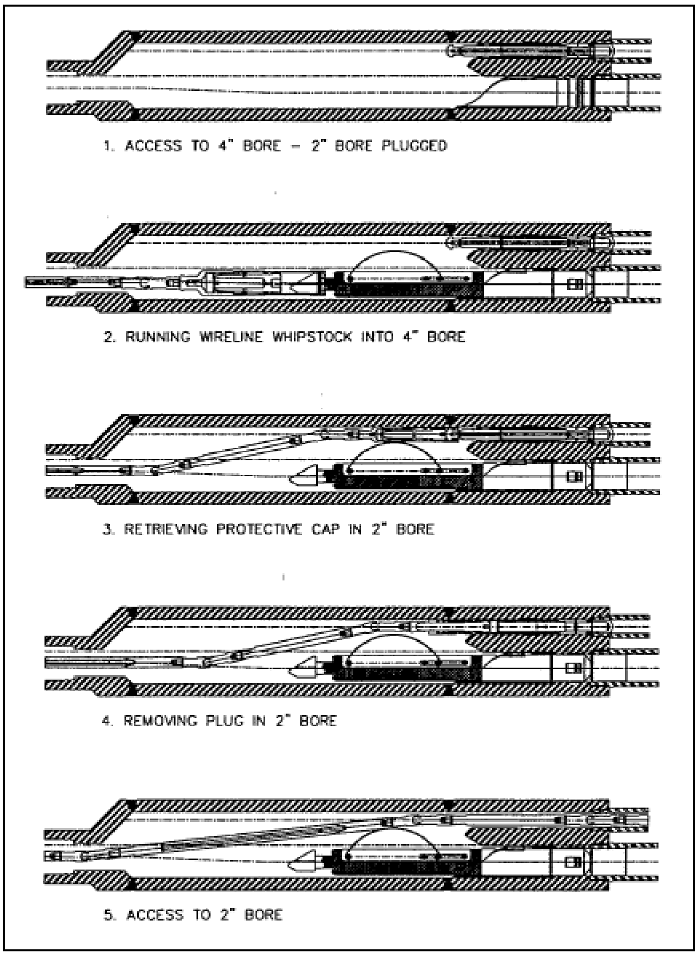

Figure 7-18 Sequence in accessing the annulus bore (Parks W.C., Smith J. D. and Weathers G.G., 1995)

The bore selector used by Sonsub Inc. has to be run in on wireline to block the production bore and the access annulus bore. This requires time to run the tool in to fix the whipstock and to withdraw the tool which is relatively expensive. Additionally each time if there is a wireline operation, there is risk of complications.

Cooper Industries Inc. - Bore Selector (US Patent 5377762)

The bore selector of the present invention a includes housing with an upper end having at least a first bore and lower end with at least second and third bores. The housing includes a central bore extending between the upper and lower ends. Tube has its upper end connected to the first bore and its lower end adjacent the second and third bores. A yoke having an aperture therethrough for passing the tube is reciprocably mounted within the bore of the housing. The yoke includes cam slots receiving guide lugs projecting from the sides of the tube. A hydraulic actuating means is also mounted in the lower end of the housing for reciprocating within the housing, the guide lugs move within the cam slots to shift the lower end of the tube and the surface surrounding the second and third bore. (Cooper Industries, 1995).

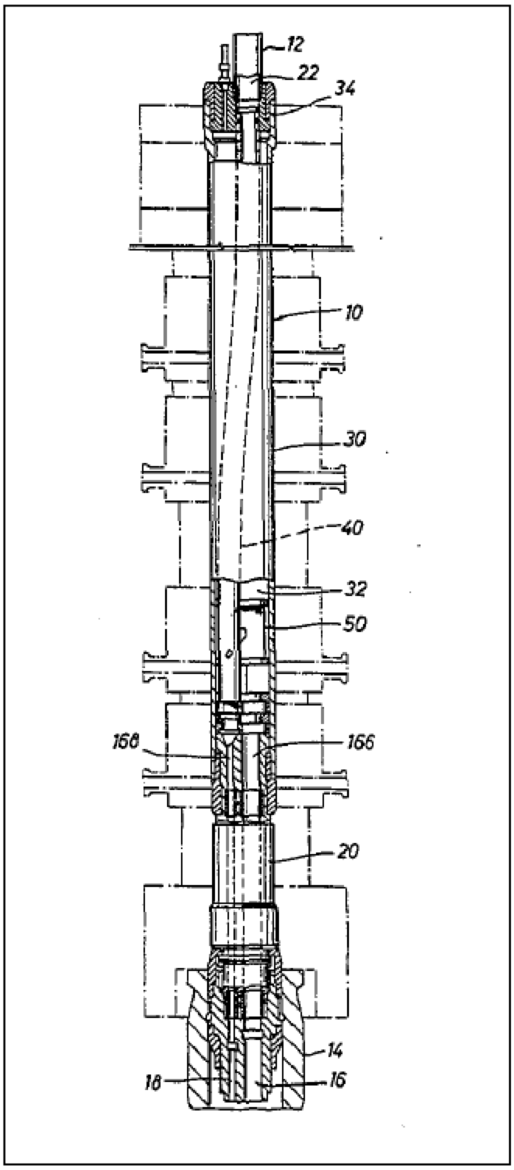

Figure 7-19 Bore selector attached to a riser at its upper end and to a running tool and wellhead at its lower end with the bore selector being shown communicating with the production bore of the wellhead(Cooper Industries, 1995)

10 – Bore Selector
12 - Riser
14 - Subsea Wellhead
16 – Production bore
18 – Annulus bore
20 – Tubing Hanger Running Tool
30 - Housing
32 - Housing
34 - Box
40 – Tube
50 – Reciprocating Yoke
166 – First bore in transition joint
168 – Second bore in transition joint

Further information regarding the use of this bore selector in industry was unable to obtain.

Expro North Sea limited - Monobore riser bore selector (US Patent 6170578 B1)

In a preferred embodiment this is achieved by using a rotatable ball valve element located in a housing disposed between the casing/tubing and a subsea test tree, the ball valve element being aperture and being rotatable between a first position whereby the aperture connects the production tubing to the production tubing bore and in a second position is rotated whereby the aperture connects the annulus bore to the tubing or the casing bore. When one of the production or annulus bores is connected to the tubing bore, then the other bore is isolated or disconnected (Expro North Sea Limited, 2001).

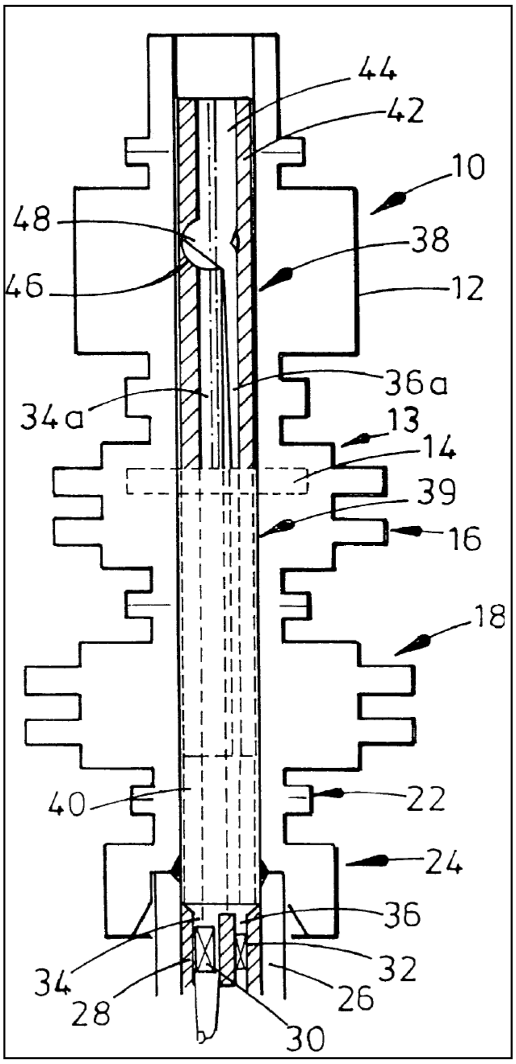

Figure 7-20 Arrangement for selecting an annulus bore instead of a production bore using a bore selector mechanism in accordance with the first embodiment(Expro North Sea Limited, 2001)

10 – Subsea wellhead assembly
12 – Annular BOP
13 – Shear ram housing
14 – BOP Shear rams
16 – BOP ram
18 - BOP ram
22 - Flange
24 – BOP Connector
26 – Subsea wellhead
28 – Tubing Hanger

30 – Wireline Plug in production bore
32 - Wireline Plug in annulus bore
34 - Production bore
34 a - Production bore in bore selector
36 – Annulus bore
36 a - Annulus bore in bore selector
38 – Bore Selector
39 – Subsea test tree
40 – Tubing Hanger Running Tool
42 – Outer Housing
44 – Top bore
46 – Rotatable ball like valve element
48 – Through aperture

In yet another embodiment of the invention the bore selector mechanism is implemented by a flapper plate mechanism which is movable by a cylindrical sleeve between a first open position whereby access to the production is blocked and there is communication between the casing or tubing and the annulus access bore and a second position whereby a sleeve is actuated to move within the housing forcing the flapper plate to an open position whereby there is communication via the sleeve between the production bore and the casing and the sleeve isolates the annulus access bore from the production bore (Expro North Sea Limited, 2001).

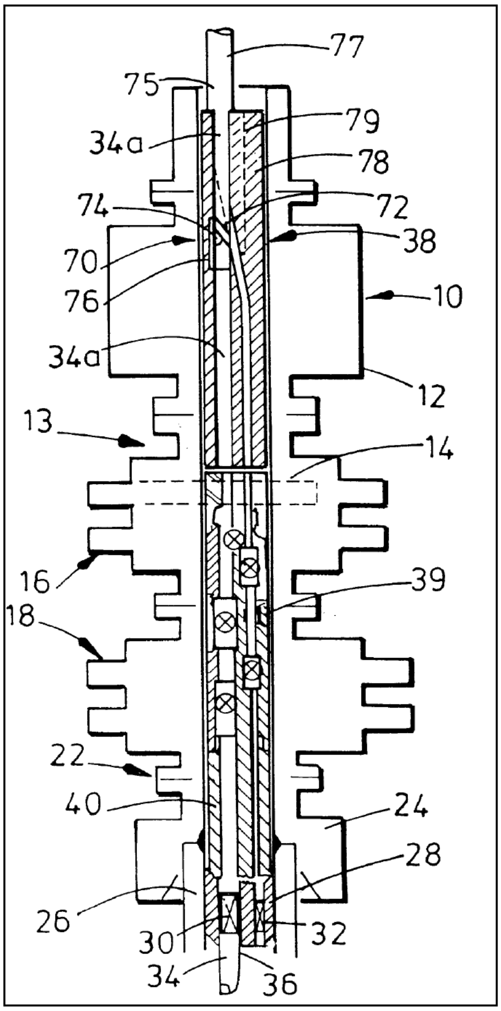

Figure 7-21 An Intervention system with a second embodiment of a bore selector apparatus (Expro North Sea Limited, 2001)

10 - Subsea wellhead assembly
12 - Annular BOP
13 - Shear ram housing
14 - BOP Shear rams
16 - BOP ram
18 - BOP ram
22 - Flange
24 - BOP Connector
26 - Subsea wellhead
28 - Tubing Hanger
30 - Wireline Plug in production bore
32 - Wireline Plug in annulus bore
34 - Production bore
34 a - Production bore in bore selector
36 – Annulus bore
36 a - Annulus bore in bore selector
38 – Bore Selector
39 – Dual bore subsea test tree
40 - Tubing Hanger Running Tool
70 – Bore Selector
72 – Flapper plate
74 – Downward facing angle
75 - Bore
76 – Tubular sleeve
77 - Casing
78 - Housing
79 – Control line

The Expro bore selector is widely used in the industry and is field proven. The second embodiment is used in the Expro bore selectors. Bore selection is determined by the position of a pivoted gate, which is actuated by a cam and piston arrangement. The cam moves axially within the Bore Selector main housing. Cycling the cam upward selects the annulus bore; conversely, cycling the cam downward selects the production bore. The bore selector is designed with a balanced Cam Actuator configuration and a Cam "dead weight" compensation mechanism which results in a "Fail As Is" system should the primary actuation pressure fail. An Auxiliary Indicator Assembly provides a visual position indication of the Bore Selector actuation. The auxiliary indicator is hydraulically connected to the actuator. As the actuator piston reaches its full stroke for either annulus or production, ports in the actuator housing are uncovered allowing control line pressure to act on indicator piston moving it to either indicate production or annulus modes.

FMC Technologies Inc. - Bore Selector (US Patent 6561276 B2)

The present invention provides a monobore riser bore selector comprising a sealed housing in which an unsealed guide is mounted for pivotal movement into the selective alignment with each of a plurality of bores; a linearly movable stem being connected to the guide to cause said pivotal movement, the stem extending through a seal in the housing so that an end of the stem is positioned externally of the sealed housing, the externally positioned end being provided with a grab formation or being connected to an actuator stem extension for movement of the stem and the guide. For example, the bore selector may be moved into alignment with either a production bore or an annulus bore of a completion, as desired. The stem may be a standard ROV/manual operated gate valve operating mechanism. The ROV operation could be via torsion or linear actuation. In addition, the standard gate valve UV stem and bonnet gasket sealing technology can be used to isolate the bore selector cavity *from the environment. This arrangement provides a reliable, flexible, and field proven design* (FMC Technologies, 2003).

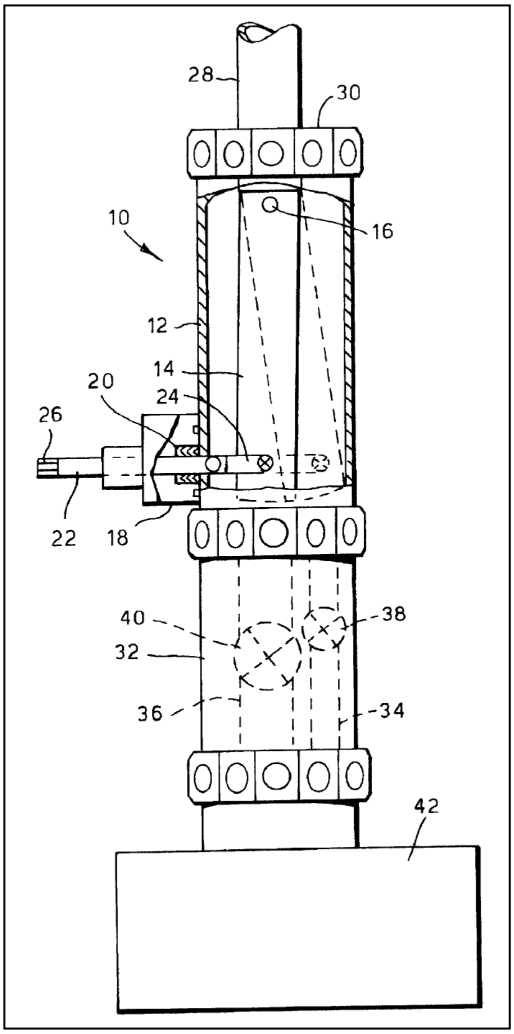

Figure 7-22 A bore selector embodying the invention connected between a monobore riser, a retainer valve block and an EDP connector(FMC Technologies, 2003)

10 – Bore selector
12 – Sealed housing
14 – Unsealed guide or tube
16 - Pivot
18 - Boss
20 - Packing
22 – Rod
24 - Linkage
26 – Grab formation

28 – Monobore riser
30 – "Speedloc" Connector
32 – Valve block
34 – Annulus bore
36 – Production bore
38 – Retainer Valve
40 - Retainer Valve
42 - EDP

The FMC bore selector is yet to be used in field as per the investigation done and hence further details are not available.

7.4 APPENDIX D - PRESSURE DESIGN CALCULATIONS

Pressure design calculation with design factor, Fd $= 0.8$

Internal Pressure (burst design) from Section 6.5.2.2 of ISO 13628-7

$Rt0{,}5$ is the specified minimum yield strength for 0,5 % total elongation at room temperature= σy

Ductility factor for materials with elongation > 14%, $\phi A5 = 1$

Temperature reduction factor yield strength Yy at 121°C= 0.91 as per *Table 7-2*
Temperature reduction factor ultimate tensile strength Yu at 121°C = 1.0 as per *Table 7-2*

Pressure Containment design factors for internal design pressure, $Fbhyd = 0.9$ as per *Table 7-7*
Pressure Containment design factors for hydrostatic test pressure, $Fbop = 0.6$ as per *Table 7-7*

Yield strength in fabricated condition,

$$\sigma yhyd = \phi A5.min(R05, 0.92X\sigma u) = 551MPa$$

(No temperature reduction factor is provided since bore selector housing is not subjected to elevated temperature during hydrostatic pressure test).

Yield strength in operating condition

$$\sigma yop = \phi A5.Yy.min(R05, 0.92.\sigma u) = 502\ MPa$$

Minimum Ultimate Tensile Strength (UTS) at room temperature, $Rm = 689\ MPa$
Ultimate Tensile strength in fabricated condition, $\sigma uhyd = \phi A5.Rm = 689\ MPa$

(No temperature reduction factor is provided since bore selector housing is not subjected to elevated temperature during hydrostatic pressure test).

Ultimate Tensile strength in operating condition $\sigma uop = \emptyset A5 \times Yu \times Rm$ = 689 MPa

Minimum burst pressure for hydrostatic test,

$$Pb\,\mathrm{hyd} = 1.1\ \times (\sigma yhyd + \sigma uhyd) \times \frac{t1hyd}{Do - t1hyd}$$
$$= 1.1\ \times (551 + 689) \times \frac{61.67}{637.74 - 61.67} = 146\ MPa$$

Minimum burst pressure for internal pressure design,

$$Pb,\mathrm{op} = 1.1\ \times (\sigma yop + \sigma uop) \times \frac{t1op}{Do - t1op} = 1.1\ \times (502 + 689) \times \frac{60.37}{637.74 - 60.37}$$
$$= 137\ MPa$$

The minimum burst pressure of the pipe at hydrostatic testing after 5 years of service and corrosion allowance taken into account for recertification

$$Pb, \text{recert} = 1.1 \times (\sigma yhyd + \sigma uhyd) \times \frac{t1op}{Do - t1op}$$
$$= 1.1 \times (551 + 689) \times \frac{60.37}{637.74 - 60.37} = 143\ MPa$$

Interaction ratio for pipe burst at hydro testing,

$$Pinterid = \frac{(Pidhyd - Podhyd)}{Fbhyd \times Pbhyd} = 0.79$$

Acceptance criteria is less than 1

Interaction ratio for pipe burst at hydro testing,

$$Pinterop = \frac{(Pidop - Podsu)}{Fbop \times Pbop} = 0.84$$

Acceptance criteria is less than 1

Interaction ratio for pipe burst at hydro testing for recertification purpose,

$$Pinterrecert = \frac{(Pidhyd - Podhyd)}{Fbhyd \times Pbrecert} = 0.80$$

Acceptance criteria is less than 1

External pressure (Hoop buckling Design) from Section 6.5.2.3 of ISO 13628-7

To meet the external pressure design,

$$\frac{(Podhb - Pidhb)}{Fhb \times Pcmin} \leq 1$$

where, $Podhb$ is the maximum external design pressure at 300 m water depth = $3.02\ MPa$
$Pidhb$ is the minimum hydrostatic internal pressure = 0
Fhb is the pipe hoop buckling (collapse) design factor from *Table 7-7* =0.67
Pc, min is the minimum pipe hoop buckling (collapse) pressure(MPa).

The step to calculate $Pcmin$ follows:

Minimum elastic hoop buckling (collapse) pressure (instability) of pipe cross-section

$$Pel,\min = \left(2 \times E \times \frac{(\frac{t1op}{Do - t1op})^3}{1 - v^2} \right) = 2 \times 205 \ \times 10^3 \times \frac{\left(\frac{60.37}{637.74 - 60.37}\right)^3}{1 - 0.3^2}$$
$$= 515\ MPa$$

Minimum plastic pressure at collapse of pipe cross-section,

$$Pp,\min = 2 \times \sigma yop \ \times \frac{t1op}{Do} = 2 \times 502 \ \times \frac{60.37}{637.74} = 95\ MPa$$

Worst ovality = 0.015 (Maximum = 1.5% and minimum = 0.25% as per Section 6.5.2.3)

The minimum hoop buckling (collapse) pressure, $Pcmin$, shall be calculated as given

$$(Pcmin - Pelmin) \times (Pcmin^2 - Ppmin^2) - \left[Pc\min \times Pel\min \times Pp\ min \times 2 \ \times fo \ \times \frac{Do}{t1op} \right] = 0$$

$$(Pcmin - 515) \times (Pcmin^2 - 95^2) - \left[Pc\min \times 515 \times 95 \times 2 \ \times 0.015 \ \times \frac{637.74}{60.37} \right] = 0$$

Solving the equation gives

$$Pcmin = 87\ MPa$$

Applying values,

External Pressure design,

$$Hinterhyd = \frac{(Podhb - Pidhb\ )}{Fhb \times Pcmin} = \frac{(3.02\ )}{0.8 \times 87} = \ 0.043$$

Acceptance criteria is less than 1.

Combined load design as per Section 6.5.3 of ISO 13628-7

The thickness for pipe used in combined load effect checks shall be the nominal thickness minus corrosion allowance given by Equation

$$t2 \ = \ tn - tca$$

where

$t2$ is the pipe wall thickness without allowances(mm);
tn is the nominal (specified) pipe wall thickness(mm);
tca is the corrosion/wear/erosion allowance(mm).

$$t2 = 63.57\ mm$$

Net internal overpressure is given by

$$\left[\frac{Te}{Fd \times Tpc}\right]^2 + \frac{|Mbm|}{Fd \times Mpc} X \sqrt{1 - \left(\frac{Pidop - Podsu}{Fd \times Pb}\right)^2} + \left(\frac{Pidop - Podsu}{Fd \times Pb}\right)^2 \leq 1$$

where,
Te is the effective tension in the pipe (MN);
Tpc is the plastic tension capacity of the pipe(MN);
Fd is the design factor as given in *Table 7-6;*
Mbm is the bending moment in the pipe(MNm);
Mpc is the plastic bending moment capacity of the pipe(MNm);
$Podsu$ is the external pressure(MPa);
$Pidop$ is the internal pressure in the pipe(MPa);
$Pcmin$ is the pipe hoop buckling (collapse) pressure(MPa)

Plastic bending moment capacity of pipe,

$$Mpc = \propto bm \times \sigma yop \times \frac{1}{6}\left[Do^3 - (Do - 2 \times t2)^3\right]$$

where, αbm is the pipe cross-section slenderness parameter;
Do is the specified or nominal pipe outside diameter(mm);
$t2$ is the pipe wall thickness without allowances(mm);

$$Mpc = 1 \times 502 \times \frac{1}{6}\left[637.74^3 - (637.74 - 2 \times 63.57)^3\right] = 10.56\ MNm$$

Design factor per Table 7-6 for working, $Fd = 0.67$

The cross sectional slenderness parameter αbm is given by equations,

$$\propto bm = 1\ for\ \frac{\sigma y \times Do}{E \times t2} \leq 0.0517$$

$$\propto bm = 1.13 - 2.58 \times \frac{\sigma y \times Do}{E \times t2}\ for\ 0.0517 < \frac{\sigma y \times Do}{E \times t2} \leq 0.1034$$

$$\propto bm = 0.94 - 0.76 \times \frac{\sigma y \times Do}{E \times t2}\ for\ 0.1034 < \frac{\sigma y \times Do}{E \times t2} \leq 0.0170$$

To find

$$\frac{\sigma y \times Do}{E \times t2} = 0.027$$

Hence $\alpha bm = 1$

Plastic tension capacity of pipe,

$$Tpc = \sigma yop \times Ac = \sigma yop \times \pi \times (Do - t2) \times t2$$
$$= 502 \times \pi \times (637.74 - 63.57) \times 63.57 = 57.56\, MN$$

where
Ac is the pipe cross-section area;
σyop is the design yield strength(MPa);

Burst pressure of pipe

$$Pb\min = 1.1 \times (\sigma yop + \sigma uop) \times \frac{t2}{Do - t2} = 1.1 \times (502 + 689) \times \frac{63.57}{637.74 - 63.57}$$
$$= 145.1\, MPa$$

Finding maximum bending moment as a function of riser tension, at maximum working pressure

$$Te = Pidop \times Ai = 13.98\, MN$$

$$\left[\frac{Te}{Fd \times Tpc}\right]^2 + \left(\frac{|Mmax1|}{Fd \times Mpc} \times \sqrt{1 - \left(\frac{Pidop - Podsu}{Fd \times Pbmin}\right)^2}\right) + \left(\frac{Pidop - Podsu}{Fd \times Pbmin}\right)^2 = 1$$

$$\left[\frac{13.98}{0.8 \times 57.56}\right]^2 + \left(\frac{|Mmax|}{0.8 \times 10.56} \times \sqrt{1 - \left(\frac{69}{0.8 \times 145.1}\right)^2}\right) + \left(\frac{69}{0.8 \times 145.1}\right)^2 = 1$$

$$Mmax1 = 5.87\, MNm$$

Set $Me = 0$

$$Te = Tmax$$

$$\left[\frac{Tmax}{Fd \times Tpc}\right]^2 + \left(\frac{|Me|}{Fd \times Mpc}\, X \sqrt{1 - \left(\frac{Pint - Podsu}{Fd \times Pb}\right)^2}\right) + \left(\frac{Pidop - Podsu}{Fd \times Pbmin}\right)^2 = 1$$

$$\left[\frac{Tmax}{0.8 \times 57.56}\right]^2 + \left(\frac{69}{0.8 \times 145.1}\right)^2 = 1$$

$$Tmax = 37\, MN$$

$$Tmax1 = Tmax - Pidop\,.Ai - Podsu.Ao = 23\, MN$$

Net external overpressure

To meet net external overpressure design criteria,

$$\left[\left(\frac{Te}{Fd\ \times Tpc}\right)^2+\left(\frac{Mbm}{0.95\times Fd\times Mpc}\right)\right]^2+\left(\frac{Podop-Pint}{Fd\times Pcmin}\right)^2\leq 1$$

Assume maximum external pressure at 300m, $Podop = 3.02\ MPa$
Fd as per internal combined from *Table 7-6* $Fd\ =\ 0.67$
Internal pressure to give worst case $Pint = 0$

$$(Pcmin-Pelmin)\times(Pcmin^2-Ppmin^2)-\left[Pc\min\times Pel\min\times Pp\ min\times 2\ \times fo\ \times\frac{Do}{t1op}\right]=0$$

Minimum elastic hoop buckling (collapse) pressure (instability) of pipe cross-section

$$Pel\min=(2\times E\times\frac{(\frac{t2}{Do-t2})^3}{1-\ v^2}=2\times 205\ \times 10^3\times\frac{\left(\frac{63.57}{637.74-63.57}\right)^3}{1-0.3^2}=611.47\ MPa$$

Minimum plastic pressure at collapse of pipe cross-section,

$$Pp\min=2\times\sigma yop\ \times\frac{t2}{Do}=2\times 502\ \times\frac{63.57}{637.74}=100\ MPa$$

The hoop buckling pressure,

$$(Pcmin-Pelmin)\times(Pcmin^2-Ppmin^2)-\left[Pc\min\times Pel\min\times Pp\ min\times 2\ \times fo\ \times\frac{Do}{t1op}\right]=0$$

$$(Pcmin-611.47)\times(Pcmin^2-100^2)-\left[Pc\min\times 611.47\times 100\ \times 2\ \times 0.015\ \times\frac{637.74}{63.57}\right]=0$$

$$Pcmin=84\ MPa$$

Find maximum bending moment as a function of riser tension, pressure end load from max working pressure

$$\left[\left(\frac{Te}{Fd\ \times Tpc}\right)^2+\left(\frac{Mbm}{0.95\times Fd\times Mpc}\right)\right]^2+\left(\frac{Podop-Pint}{Fd\times Pcmin}\right)^2=1$$

$$\left[\left(\frac{13.98}{0.8\times 57.56}\right)^2+\left(\frac{Mbm}{0.95\times 0.67\times 10.56}\right)\right]^2+\left(\frac{3.02}{0.8\times 84}\right)^2=1$$

$$Mmax2=7.28MNm$$

Given

$$Te = Tmax$$

$$Me = 0$$

$$\left[\left(\frac{Tmax}{Fd \ \times Tpc}\right)^2 + \left(\frac{Me}{0.95 \times Fd \times Mpc}\right)\right]^2 + \left(\frac{Podop - Pint}{Fd \times Pcmin}\right)^2 = 1$$

$$\left[\left(\frac{Tmax}{0.8 \ \times 57.56}\right)^2\right]^2 + \left(\frac{3.02}{0.8 \times 84}\right)^2 = 1$$

$$Tmax = 46 \ MN$$

$$Tmax2 = Tmax - Te = 32 \ MN$$

Find max bending and tension combined loads net internal and external over pressure

At Maximum Working Pressure:

$$Tmax \ = \ min(Tmax1, Tmax2) \ MN \ = \ min(23, 32) \ MN$$

$$Mmax = \ min(Mmax1, Mmax2) \ MNm = \ min(5.87, 7.28) \ MNm$$

$$\boxed{\begin{array}{c} \boldsymbol{Tmax \ = \ 23 \ MN} \\ \boldsymbol{Mmax = \ 5.87 \ MNm} \end{array}}$$

Summary of results:

Calculation Summary

All ratio has to be equal or less than 1.

Internal hydro test, $Pinterid \ = \ 0.79$
Internal operating test, $Pinterop \ = \ 0.84$
Internal hydro test for recertification, $Pinterrecert \ = \ 0.80$
External collapse, $Hinterhyd \ = \ 0.043$

Maximum capacities at MWP:

ISO Tensile Capacity, Tmax = 23 MN at zero bending.
ISO Bending Capacity, Mmax = 5.87 MNm at zero tension.

Pressure design calculation for design factor, Fd = 1

Internal Pressure (burst design) from Section 6.5.2.2 of ISO 13628-7

$Rt0{,}5$ is the specified minimum yield strength for 0,5 % total elongation at room temperature = σy

Ductility factor for materials with elongation > 14%, $\phi A5 = 1$

Temperature reduction factor yield strength Yy at 121°C= 0.91 as per *Table 7-2*
Temperature reduction factor ultimate tensile strength Yu at 121°C = 1.0 as per *Table 7-2*

Pressure Containment design factors for internal design pressure, $Fbhyd = 0.9$ as per *Table 7-7*
Pressure Containment design factors for hydrostatic test pressure, $Fbop = 0.6$ as per *Table 7-7*

Yield strength in fabricated condition,

$$\sigma yhyd = \phi A5.min(R05, 0.92X\sigma u) = 551MPa$$

(No temperature reduction factor is provided since bore selector housing is not subjected to elevated temperature during hydrostatic pressure test).

Yield strength in operating condition,

$$\sigma yop = \phi A5.Yy.min(R05, 0.92.\sigma u) = 502\ MPa$$

Minimum Ultimate Tensile Strength (UTS) at room temperature, $Rm = 689\ MPa$
Ultimate Tensile strength in fabricated condition, $\sigma uhyd = \phi A5.Rm = 689\ MPa$

(No temperature reduction factor is provided since bore selector housing is not subjected to elevated temperature during hydrostatic pressure test).

Ultimate Tensile strength in operating condition $\sigma uop = \emptyset A5 \times Yu \times Rm$ = 689 MPa

Minimum burst pressure for hydrostatic test,

$$Pb\,\mathrm{hyd} = 1.1 \times (\sigma yhyd + \sigma uhyd) \times \frac{t1hyd}{Do - t1hyd}$$
$$= 1.1 \times (551 + 689) \times \frac{61.67}{637.74 - 61.67} = 146\ MPa$$

Minimum burst pressure for internal pressure design,

$$Pb,\mathrm{op} = 1.1 \times (\sigma yop + \sigma uop) \times \frac{t1op}{Do - t1op} = 1.1 \times (502 + 689) \times \frac{60.37}{637.74 - 60.37}$$
$$= 137\ MPa$$

The minimum burst pressure of the pipe at hydrostatic testing after 5 years of service and corrosion allowance taken into account for recertification,

$$Pb,\text{recert} = 1.1\ \times (\sigma yhyd + \sigma uhyd) \times \frac{t1op}{Do - t1op}$$

$$= 1.1\ \times (551 + 689) \times \frac{60.37}{637.74 - 60.37} = 143\ MPa$$

Interaction ratio for pipe burst at hydro testing,

$$Pinterid = \frac{(Pidhyd - Podhyd)}{Fbhyd\ \times Pbhyd} = 0.79$$

Acceptance criteria is less than 1

Interaction ratio for pipe burst at hydro testing,

$$Pinterop = \frac{(Pidop - Podsu)}{Fbop\ \times Pbop} = 0.84$$

Acceptance criteria is less than 1

Interaction ratio for pipe burst at hydro testing for recertification purpose,

$$Pinterrecert = \frac{(Pidhyd - Podhyd)}{Fbhyd\ \times Pbrecert} = 0.80$$

Acceptance criteria is less than 1

External pressure (Hoop buckling Design) Section 6.5.2.3 of ISO 13628-7

To meet the external pressure design as defined by

$$\frac{(Podhb - Pidhb\ )}{Fhb \times Pcmin} \leq\ 1$$

where, $Podhb$ is the maximum external design pressure at 300 m water depth = $3.02\ MPa$
$Pidhb$ is the minimum hydrostatic internal pressure = 0
Fhb is the pipe hoop buckling (collapse) design factor, obtained from *Table 7-8* = 0.67
Pc,min is the minimum pipe hoop buckling (collapse) pressure(MPa).

The step to calculate $Pcmin$ follows,

Minimum elastic hoop buckling (collapse) pressure (instability) of pipe cross-section,

$$Pel,\min = \left(2 \times E \times \frac{(\frac{t1op}{Do - t1op})^3}{1 - v^2} \right) = 2 \times 205 \times 10^3 \times \frac{\left(\frac{60.37}{637.74 - 60.37}\right)^3}{1 - 0.3^2}$$
$$= 515\ MPa$$

Minimum plastic pressure at collapse of pipe cross-section,

$$Pp,\min = 2 \times \sigma yop \times \frac{t1op}{Do} = 2 \times 502 \times \frac{60.37}{637.74} = 95\ MPa$$

Worst ovality = 0.015 (Maximum = 1.5% and minimum = 0.25% as per Section 6.5.2.3)

The minimum hoop buckling (collapse) pressure, $Pcmin$, shall be calculated as given

$$(Pcmin - Pelmin) \times (Pcmin^2 - Ppmin^2) - \left[Pc\min \times Pel\min \times Pp\,min \times 2 \times fo \times \frac{Do}{t1op}\right] = 0$$

$$(Pcmin - 515) \times (Pcmin^2 - 95^2) - \left[Pc\min \times 515 \times 95 \times 2 \times 0.015 \times \frac{637.74}{60.37}\right] = 0$$

Solving the equation gives,

$$Pcmin = 87\ MPa$$

Applying values,

External Pressure design,

$$Hinterhyd = \frac{(Podhb - Pidhb)}{Fhb \times Pcmin} = \frac{(3.02)}{1 \times 87} = 0.035$$

Acceptance criteria is less than 1

Combined load design as per Section 6.5.3 of ISO 13628-7

The thickness for pipe used in combined load effect checks shall be the nominal thickness minus corrosion allowance given by Equation

$$t2 = tn - tca$$

where

$t2$ is the pipe wall thickness without allowances(mm);
tn is the nominal (specified) pipe wall thickness(mm);
tca is the corrosion/wear/erosion allowance(mm).

$$t2 = 63.57\ mm$$

Net internal overpressure is given by

$$\left[\frac{Te}{Fd\ \times\ Tpc}\right]^2 + \frac{|Mbm|}{Fd\ \times\ Mpc}\ X\ \sqrt{1 - \left(\frac{Pidop - Podsu}{Fd\ \times\ Pb}\right)^2} + \left(\frac{Pidop - Podsu}{Fd\ \times\ Pb}\right)^2 \leq 1$$

where,
Te is the effective tension in the pipe(MN);
Tpc is the plastic tension capacity of the pipe(MN);
Fd is the design factor as given in *Table 7-6*;
Mbm is the bending moment in the pipe(MNm);
Mpc is the plastic bending moment capacity of the pipe(MNm);
$Podsu$ is the external pressure(MPa);
$Pidop$ is the internal pressure in the pipe(MPa);
$Pcmin$ is the pipe hoop buckling (collapse) pressure(MPa).

Plastic bending moment capacity of pipe,

$$Mpc = \propto bm\ \times\ \sigma yop\ \times\ \frac{1}{6}\ [Do^3 -\ (Do - 2 \times t2)^3]$$

where, αbm is the pipe cross-section slenderness parameter;
Do is the specified or nominal pipe outside diameter(mm);
$t2$ is the pipe wall thickness without allowances(mm);

$$Mpc = 1 \times 502\ \times \frac{1}{6}\ [637.74^3 - (637.74 - 2\ \times 63.57)^3] = 10.56\ MNm$$

Design factor per table for working, $Fd\ =\ 0.67$

The cross sectional slenderness parameter αbm is given by equations

$$\propto bm = 1\ for\ \frac{\sigma y\ \times\ Do}{E\ \times\ t2} \leq 0.0517$$

$$\propto bm = 1.13 - 2.58\ \times\ \frac{\sigma y\ \times\ Do}{E\ \times\ t2}\ for\ 0.0517\ <\ \frac{\sigma y\ \times\ Do}{E\ \times\ t2} \leq 0.1034$$

$$\propto bm = 0.94 - 0.76\ \times\ \frac{\sigma y\ \times\ Do}{E\ \times\ t2}\ for\ 0.1034\ <\ \frac{\sigma y\ \times\ Do}{E\ \times\ t2} \leq 0.0170$$

To find

$$\frac{\sigma y\ \times Do}{E \times t2} = 0.027$$

Hence $\alpha bm = 1$

Plastic tension capacity of pipe

$$Tpc = \sigma yop \times Ac = \sigma yop \times \pi \times (Do - t2) \times t2$$
$$= 502 \times \pi \times (637.74 - 63.57) \times 63.57 = 57.56\, MN$$

where
Ac is the pipe cross-section area;
σyop is the design yield strength(MPa);

Burst pressure of pipe

$$Pb\min = 1.1 \times (\sigma yop + \sigma uop) \times \frac{t2}{Do - t2} = 1.1 \times (502 + 689) \times \frac{63.57}{637.74 - 63.57}$$
$$= 145.1\, MPa$$

Finding maximum bending moment as a function of riser tension, at maximum working pressure

$$Te = Pidop \times Ai = 13.98\, MN$$

$$\left[\frac{Te}{Fd \times Tpc}\right]^2 + \left(\frac{|Mmax1|}{Fd \times Mpc} \times \sqrt{1 - \left(\frac{Pidop - Podsu}{Fd \times Pbmin}\right)^2}\right) + \left(\frac{Pidop - Podsu}{Fd \times Pbmin}\right)^2 = 1$$

$$\left[\frac{13.98}{1.0 \times 57.56}\right]^2 + \left(\frac{|Mmax|}{1.0 \times 10.56} \times \sqrt{1 - \left(\frac{69}{1.0 \times 145.1}\right)^2}\right) + \left(\frac{69}{1.0 \times 145.1}\right)^2 = 1$$

$$Mmax1 = 8.57\, MNm$$

Set $Me = 0$

$$Te = Tmax$$

$$\left[\frac{Tmax}{Fd \times Tpc}\right]^2 + \left(\frac{|Me|}{Fd \times Mpc} X \sqrt{1 - \left(\frac{Pint - Podsu}{Fd \times Pb}\right)^2}\right) + \left(\frac{Pidop - Podsu}{Fd \times Pbmin}\right)^2 = 1$$

$$\left[\frac{Tmax}{0.8 \times 57.56}\right]^2 + \left(\frac{69}{0.8 \times 145.1}\right)^2 = 1$$

$$Tmax = 50.64\, MN$$

$$Tmax1 = Tmax - Pidop\,.\,Ai - Podsu.\,Ao = 36.66\, MN$$

Net external overpressure

To meet net external overpressure design criteria,

$$\left[\left(\frac{Te}{Fd\ \times Tpc}\right)^2+\left(\frac{Mbm}{0.95\times Fd\times Mpc}\right)\right]^2+\left(\frac{Podop-Pint}{Fd\times Pcmin}\right)^2\leq 1$$

Assume maximum external pressure at 300m, $Podop = 3.02\ MPa$
Fd as per internal combined from *Table 7-6*, $Fd\ =\ 0.67$
Internal pressure to give worst case $Pint = 0$

$$(Pcmin-Pelmin)\times(Pcmin^2-Ppmin^2) \\ -\left[Pc\min\times Pel\min\times Pp\ min\times 2\ \times fo\ \times\frac{Do}{t1op}\right]=0$$

Minimum elastic hoop buckling (collapse) pressure (instability) of pipe cross-section

$$Pel\min=(2\times E\times\frac{(\frac{t2}{Do-t2})^3}{1-\ v^2}=2\times 205\ \times 10^3\times\frac{\left(\frac{63.57}{637.74-63.57}\right)^3}{1-0.3^2}=611.47\ MPa$$

Minimum plastic pressure at collapse of pipe cross-section,

$$Pp\min=2\times\sigma yop\ \times\frac{t2}{Do}=2\times 502\ \times\frac{63.57}{637.74}=100\ MPa$$

The hoop buckling pressure

$$(Pcmin-Pelmin)\times(Pcmin^2-Ppmin^2) \\ -\left[Pc\min\times Pel\min\times Pp\ min\times 2\ \times fo\ \times\frac{Do}{t1op}\right]=0$$

$$(Pcmin-611.47)\times(Pcmin^2-100^2) \\ -\left[Pc\min\times 611.47\times 100\ \times 2\ \times 0.015\ \times\frac{637.74}{63.57}\right]=0$$

$$Pcmin=84\ MPa$$

Find maximum bending moment as a function of riser tension, pressure end load from max working pressure

$$\left[\left(\frac{Te}{Fd\ \times Tpc}\right)^2+\left(\frac{Mbm}{0.95\times Fd\times Mpc}\right)\right]^2+\left(\frac{Podop-Pint}{Fd\times Pcmin}\right)^2=1$$

$$\left[\left(\frac{13.98}{1.0\times 57.56}\right)^2+\left(\frac{Mbm}{0.95\times 1.0\times 10.56}\right)\right]^2+\left(\frac{3.02}{1.0\times 84}\right)^2=1$$

$$Mmax2=9.43MNm$$

Given

$$Te=Tmax$$

$$Me = 0$$

$$\left[\left(\frac{Tmax}{Fd \times Tpc}\right)^2 + \left(\frac{Me}{0.95 \times Fd \times Mpc}\right)\right]^2 + \left(\frac{Podop - Pint}{Fd \times Pcmin}\right)^2 = 1$$

$$\left[\left(\frac{Tmax}{0.8 \times 57.56}\right)^2\right]^2 + \left(\frac{3.02}{0.8 \times 84}\right)^2 = 1$$

$$Tmax = 57.52\ MN$$

$$Tmax2 = Tmax - Te = 43.54\ MN$$

Find max bending and tension combined loads net internal and external over pressure

At Maximum Working Pressure:

$$Tmax = min(Tmax1, Tmax2)\ MN = min(36.66, 43.54)\ MN$$

$$Mmax = min(Mmax1, Mmax2)\ MNm = min(8.57, 9.43)\ MNm$$

$$\boxed{\begin{array}{c} \boldsymbol{Tmax = 36.66\ MN} \\ \boldsymbol{Mmax = 8.57\ MNm} \end{array}}$$

Summary of results:

Calculation Summary

All ratio has to be equal or less than 1.

Internal hydro test, $Pinterid = 0.79$.
Internal operating test, $Pinterop = 0.84$.
Internal hydro test for recertification, $Pinterrecert = 0.80$.
External collapse, $Hinterhyd = 0.035$.

Maximum capacities at MWP

ISO Tensile Capacity, Tmax =36.66 MN at zero bending.
ISO Bending Capacity, Mmax = 8.57 MNm at zero tension.