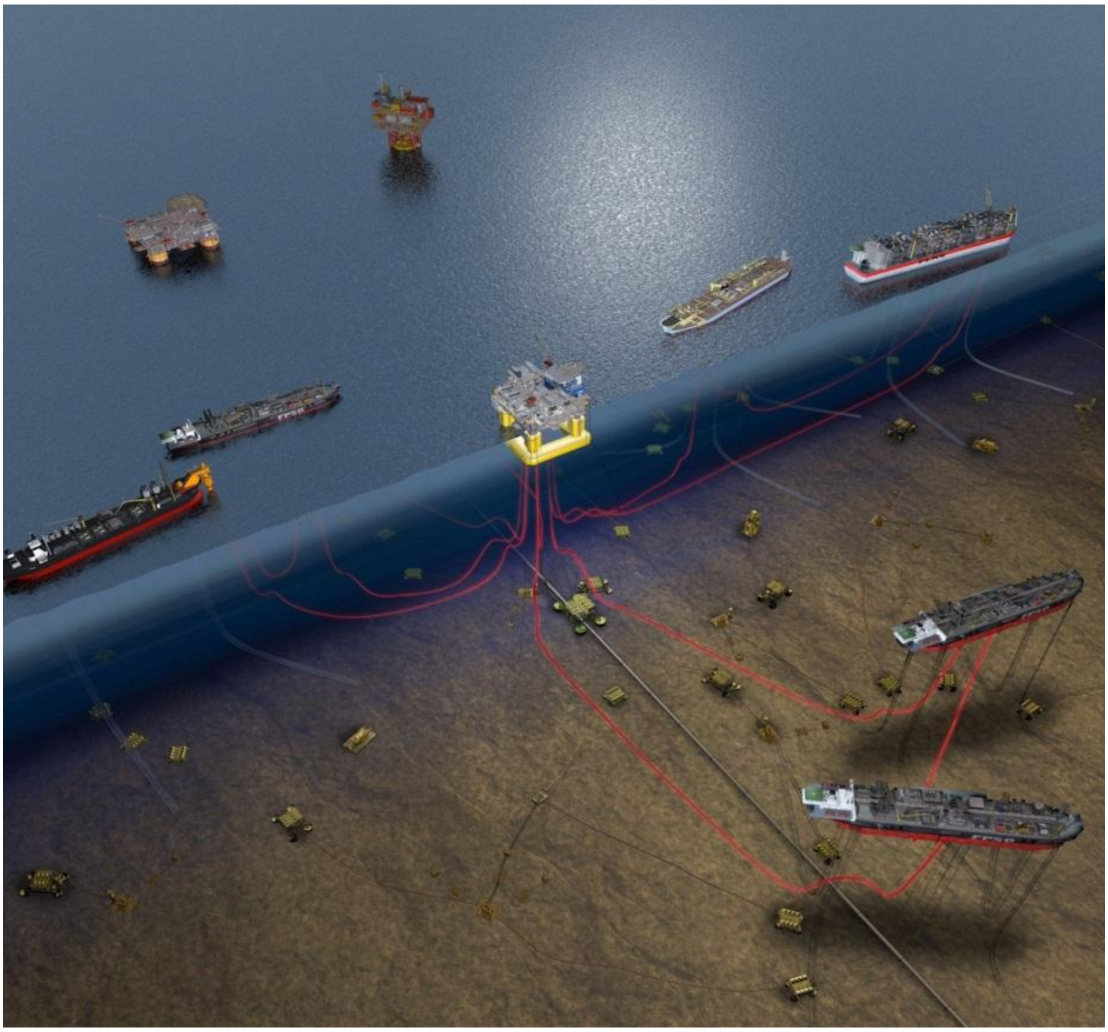
Subsea Facilities - Technology Developments, Incidents and Future Trends



Petroleumstilsynet

PETROLEUM SAFETY AUTHORITY NORWAY

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Customer:	Petroleumstilsynet Biblioteket Postboks 599 4003 Stavanger Norway	
Contact person:	Erik Hegelstad	
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Task and objective:

DNV GL has made this report on behalf of Petroleum Safety Authority (PSA). The report highlights the technology that is being used in subsea oil and gas production. The report describes challenges and incidents. Known and experienced failure modes and degradation mechanisms are also detailed. Future developments of the technology and trends are discussed. A number of national and international databases has been examined and consulted in this work. References are given to other initiatives in order to develop this industry further.

The report will be educational and raise awareness to the challenges this industry faces. It will assist new organisations, as suppliers or new operators entering the NCS to capture best practice and lessons learned from about 30 years of subsea development. It can be seen as a guideline explaining different selection criterions. The report also gives an overview of the main elements in an integrity management system.

In the preparation of this report several databases have been examined, where some are made by authorities while other are made by different private entities. The reporting format and data that is possible to extract varies and this also goes for the accuracy of the reported incidents. The experience of using those sources is also discussed in this document.

The report is also discussing selection criteria for different seabed architecture. In this evaluation the reasoning for why there are relatively large differences in how subsea fields are being designed for in different regions will be given.

The global network within DNV GL has been consulted to also capture international trends and incidents to this business.

The openness in incident databases varies for different countries, where the Norwegian society stands out as' sharing. This is also reflected in this report where the details from NCS are better described than what can be seen from foreign regions.

Prepared by:	Verified by:	Approved by:
Svein Gundersen	Bente H Leinum	Bjørn Søgård
Kari Lønvik	Christian Markussen	
Bjørn Søgård		
Christian Markussen		
Per Wallin		

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Reference to part of this report which may lead to misinterpretation is not permissible.

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1 EXECUTIVE SUMMARY

In the development of offshore oil and gas fields, more and more of the fields are utilising subsea technologies. An increasing number of subsea wells and trees in operation both at the Norwegian Continental Shelf (NCS) as well as in other regions for offshore activities can be seen. This leads to an increase in the volume for maintenance of subsea facilities and wells in the years to come. In addition, the effect of an ageing population of systems in operation will also require maintenance and/or replacement. Today a number of fields are also being assessed for life extension, which also contributes to increased number of systems in operation as the average years in service increases.

An increased risk level can also be visualised with more challenges ahead. This is because the industry prepares for going deeper, colder, more remote and with more demanding production fluids. In today’s society there are also ongoing discussions whether to move or not to move into more environmentally sensitive areas. Complexity is now also taking step changes with the realisation of subsea processing and compression. Finally, systems are getting more complex, harder to test and to predict prospective failure modes.

These factors mentioned above may lead to an overall higher risk level than the industry has handled before. In addition the no acceptance for incidents has become stricter, both seen from the authorities and the society’s point of view. The increased risk level has to be mitigated by focusing on planning, engineering, fabrication and realisation of projects.

For these reasons mentioned above the Petroleum Safety Authority has taken the initiative to commission this report from DNV GL to bring focus and clarity into these issues.

This document describes current technologies, experiences, incidents and future technology trends. It can be seen as a contribution to increase the awareness to personnel or organisations working in or entering into this industry.

The document has consulted several databases. Some databases are operated and maintained by authorities and others are operated by private entities. These databases have been consulted for different purposes;

- To provide facts for reported technology choices sorted on geographical areas
- To trend incidents which have led to spill of hydrocarbons to the environment

The focus for this report has been incidents resulting in loss of containment. Incidents that have led to loss of production time or ability to produce have not been reported. This is mainly due to the lack of such information. It is in general a challenge to extract information that can be used for trending or establishing root cause for an incident from these open sources. It is recommended and considered of outmost usefulness and importance, with respect to HSE and technology development, that the industry take further responsibility for knowledge sharing and provide more transparency through international databases where useful information can be retrieved.

For future trends and technologies documents compiled by industry joint efforts have been used rather than marketing materials and company plans.

The document also contains a comprehensive list of degradation mechanisms, which forms a sound background for designers, operators and personnel involved in integrity management processes.

2 INTRODUCTION

The development of subsea technology has been based on a step by step development over the years adding more and more functionalities to the various systems. Today, tremendous technology developments are ongoing, driven by the goal of locating processing systems on the seabed, illustration in Figure 2.1. The increase in complexity is extensive compared to the early beginning with North East Frigg some 30 years ago towards the subsea compression facilities that are currently being realised. There has been a development in technological areas such as; design, materials, flow assurance, control and instrumentation, installation and operation. The driver has been to develop simpler and more cost efficient ways to produce, process and transport oil and gas offshore. In order to achieve this the industry is relying more and more on utilising subsea system as part of this value creation, and the subsea part of a field development is getting more advanced. The number of installed subsea XT today is about 800 on the NCS, and approx. 5000 on a worldwide basis. These numbers are forecasted to increase in the years to come, both with known technology and more complex developments utilising new technology.

Experience both from the North Sea as well as globally shows that accidents related to subsea facilities, as all other offshore oil and gas activities, may have potential for major accidents.

The report describes current status of the industry and future trends. Mechanisms related to degradation and ageing, and the effect this has on the robustness in operation are also described. An important aspect today is that offshore and subsea facilities are typically being operated beyond their original intended service life and thus the need for a proper life extension process is required. The effectiveness of the life extension process reveals another important aspect, namely system integrity management. The ability to document safe and reliable operation as well as enabling life extension is highly dependent on a well implemented and effective integrity management system.

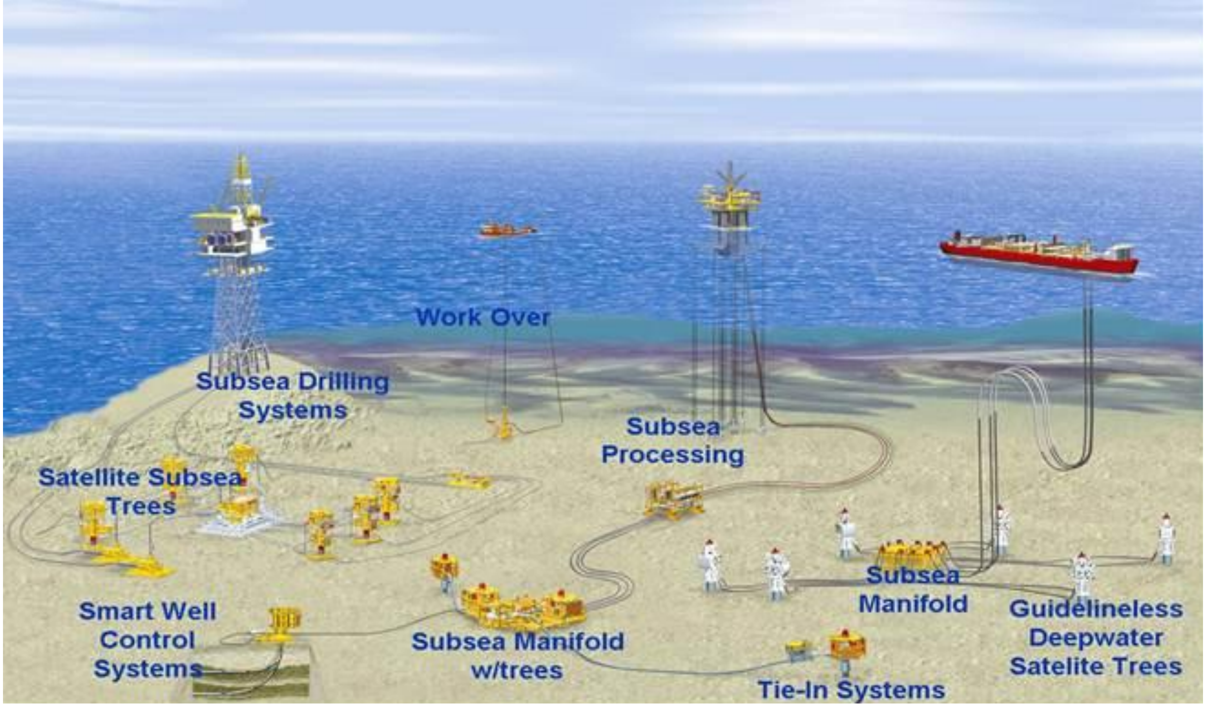


Figure 2.1 Major systems in a subsea field development

2.1 Scope of work

This report covers subsea trees, manifolds, control system, structures, wellheads, umbilical (see Figure 2.2) and includes the following topics:

- Technology - Historical trends, future trends, developments and challenges both on NCS and globally
- An overview of the most serious incidents on NCS and globally.
- Overview and outlook - NCS and globally.
- Integrity management (from design to operation).
- Degradation mechanisms and failure modes.
- Inspection, maintenance and monitoring methodologies.
- Recommendations for improvements and knowledge sharing.

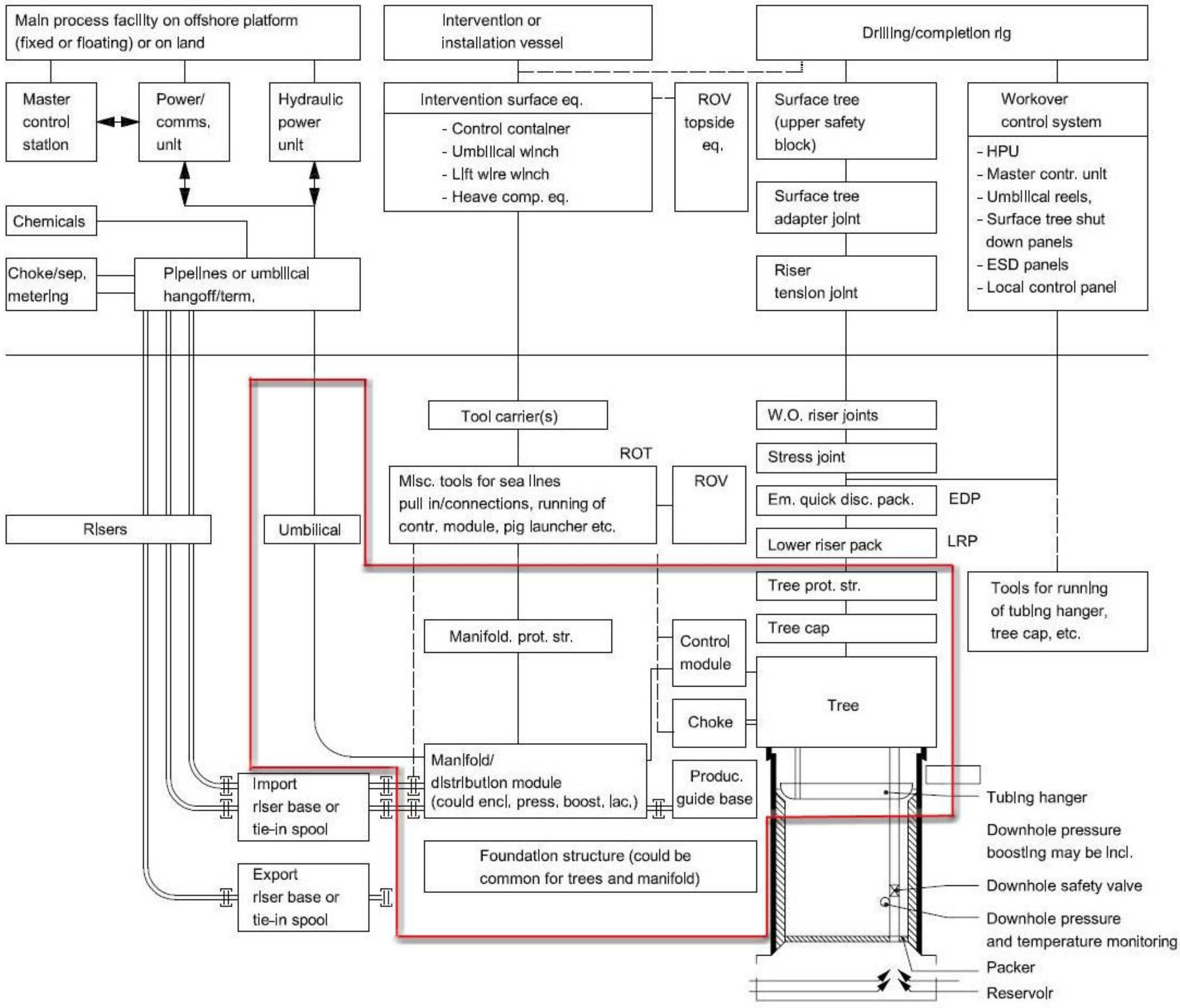


Figure 2.2 The battery limit covered by this report are illustrated by the red line (The figure is reproduced from Figure A.1 from ISO 13628-1)

3 TECHNOLOGY – HISTORICAL TRENDS

3.1 General subsea solutions

Since the beginning of the oil industry's migration from dry land into shallow-water areas via wellhead platform solutions, and subsequently into deeper water depths of a few hundred meters, the development of reserves in greener areas and water depths down to more than 3000 metres has brought on significantly greater volumes of reserves. Such innovation calls for better subsea solutions that meets new requirements and includes advances in drilling equipment, installation technology and control systems.

The subsea industry is in a transition period where the advancements in technology are now taking major steps in the way of more advanced subsea systems being designed and installed. Examples of this are the emergence of subsea processing, which includes technologies capable of separating different fluid phases and boosting the fluids using pumps or compressors. Figure 3**.1** illustrates the upstream expenditure growth for subsea vs rest of oil and gas industry at NCS.

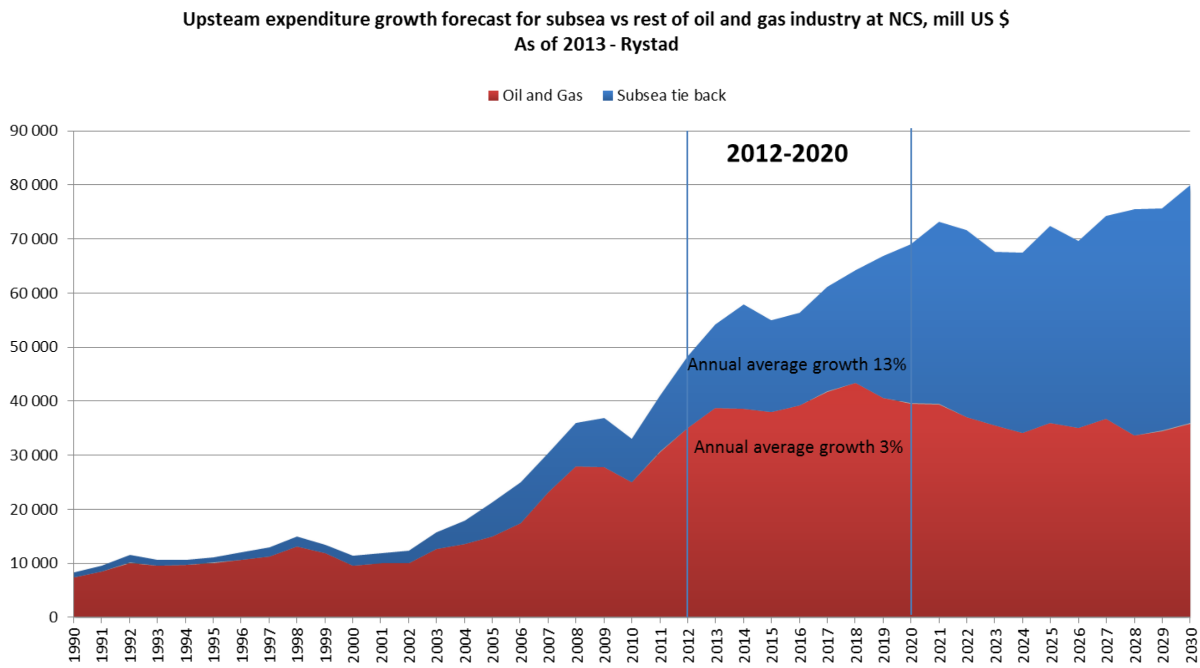


Figure 3.1 Subsea grows faster than general oil and gas at NCS (Based on figures from Rystad Energy)

Tie-backs and Life Extension: An important aspect today is that existing infrastructure and platforms as well as pipelines are utilized with new subsea prospect being tied into old platforms. These developments are often characterized by utilizing conventional and cost effective solutions and may therefore not be regarded as technology drivers. Due to known production regime, these developments may be developed efficiently and with little effort spend on tailored design. Key to success is often quick deliveries without sacrificing quality or safety. A number of such developments have been done by new companies entering the NCS, or companies that previously have been licensee partner in other fields. Examples of tie-in projects are; Oselvar tied to Ula, Trym tied to Harald, Brynhild tied to Pierce and Jette tied into Jotun. There are also fields that have been developed with cross-border transportation such as Trym producing to Danish territory and Brynhild to UK.

Fast-track: Statoil has introduced their portfolio of fast track projects. As the operator look for faster and more economical ways to extract oil from smaller fields or tying in to existing installations, the industry has been looking into how projects can be executed faster and at the same time maintaining the same quality. To meet these needs, standard catalogues of Subsea Production Systems (SPS) are under development /48/. The result is so called fast-track projects where no new technology is introduced for further qualification in order to save time. According to Statoil, fast-track projects are subsea tie-in projects in which standardized solutions are used to reduce the time from discovery to production from 5 to about 2 years. Reducing costs by 30% is also an ambition for fast-track projects. Experience transfer from fast-track projects is the key, in particular in simplification and swift implementation of improvements. An example of a fast track project is Skuld – considered as Statoil's most complex fast-track and the largest of the development fields in the fast-track portfolio (Figure 3-2).

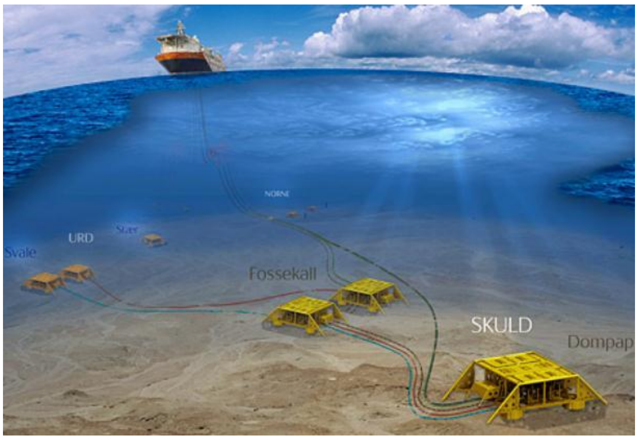


Figure 3.2 Illustration showing fast-track project Skuld (Image: www.offshoreenerytoday)

3.2 Subsea architecture, Regional differences

The normal NCS subsea field developments are based on the subsea equipment being located in template structures. The template is the foundation that carries the weight and loads of the structure, and supports the wellhead and drilling activities, manifold and control system as well as the protection structure. The protection structure covers the template, manifold and the trees to protect the equipment from third party damages as e.g. dropped objects, anchors or trawl equipment. Figure 3.3 shows a typical NCS subsea template.

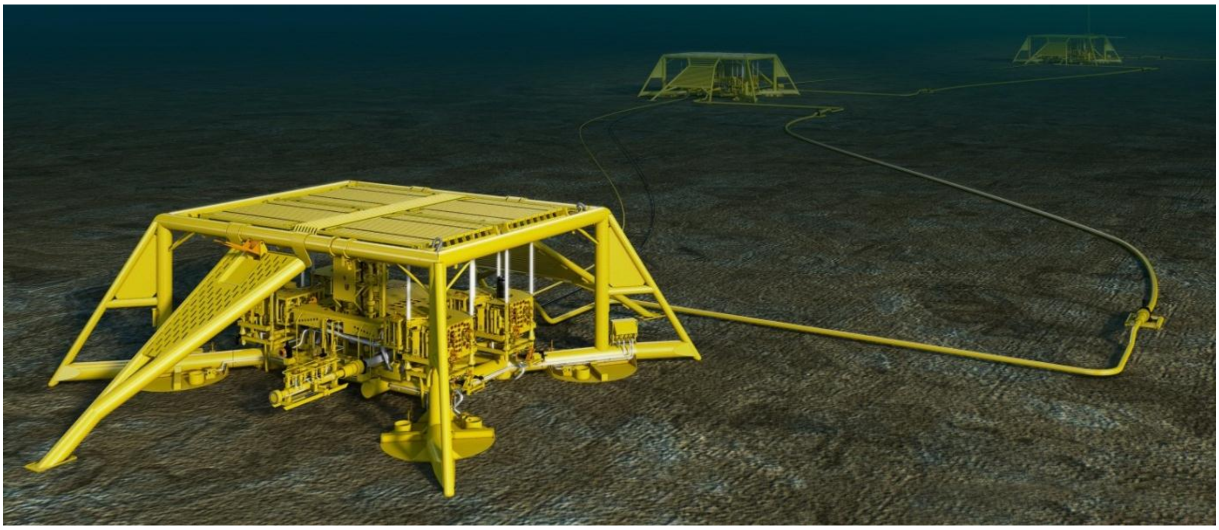


Figure 3.3 Typical NCS tie-back solution (Image: Statoil ASA)

In other parts of the world where there is not a requirement that the equipment is overtrawlable the typical solution is to distribute the modules (trees, manifolds, etc.) with each having its own foundation on the seabed. This will often be described as a clustered manifold solution, where a number of wells with XT's are located as standalone units, producing through a jumper spool to a comingling manifold. Here the control system is also a central unit (often referred to as the Subsea Distribution Unit (SDU)) and distributes control signals, electrical and hydraulic power to manifold and Subsea Control Modules (SCM) as well as distribution of injection chemicals. In ultra-deep water where the seabed tends to be softer, the SDU will be located onto the foundation that carries the manifold. Figure 3.4 shows a typical GOM installation.

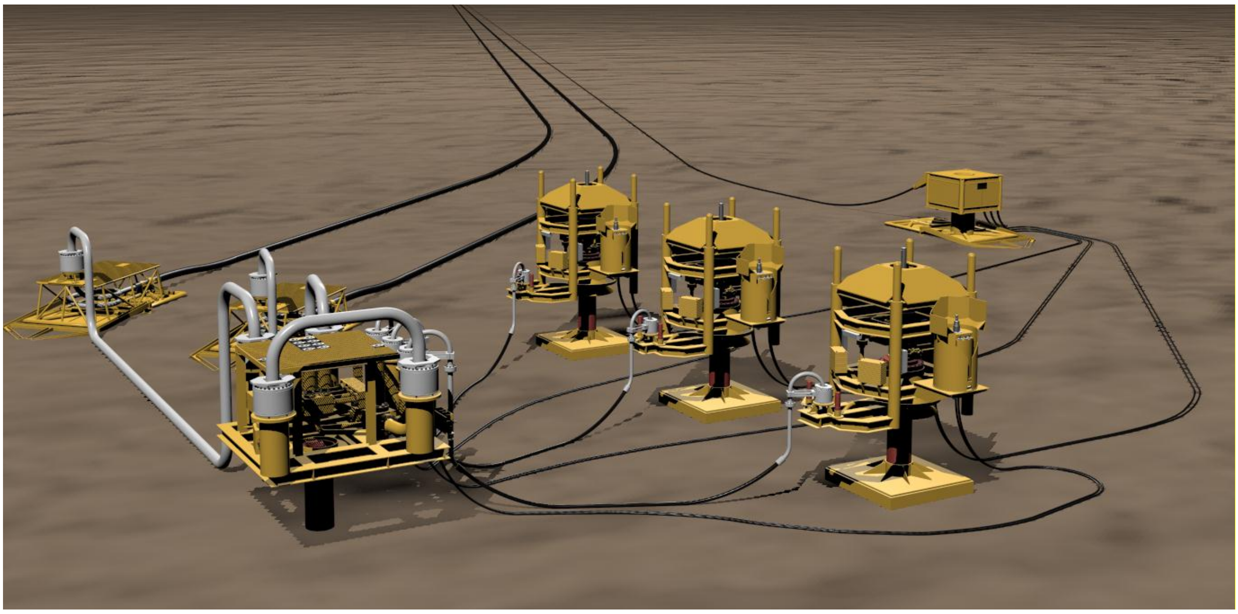


Figure 3.4 Typical GOM subsea tie-back

3.3 Wellhead system

A wellhead is the components at the surface or seabed of a well that provides the structural and pressure-containing interface for the drilling and production equipment. The wellhead is supported by the conductor housing, normally a 30" or 36" casing against the foundation cement and the soil. The wellhead also supports the pressure containing casings and also the production tubing when vertical trees are used. The standard size of the high pressure wellhead being used all over the world is 18 ¾". The exemption to this is Brazil where there is a tradition of using 16 ¾" wellheads. The interface profile used for locking the subsea tree or the drilling BOP to the wellhead is today dominated by the standard H4 wellhead profile.

Today a lot of effort is spent in order to verify and predict the wellhead fatigue capacity. The fatigue capacity is the wellhead systems capacity to withstand a dynamic load generated from the riser and BOP. The drilling marine riser is the most severe, but also smaller and lighter work-over risers can create fatigue loads. The industry-wide interest in this is driven by the fact that both drilling BOP's and drilling rigs are getting larger and heavier resulting in increased fatigue loads on the wellhead. Drilling deeper and more advanced wells is more time consuming and thus the wellhead is exposed to the drilling loads for a longer period of time than what the industry traditionally have experience with. Both the operators and the equipment manufacturers are working hard to address these issues.

Today, wellhead systems are designed to standard pressure classes which for offshore / subsea applications are 10,000 and 15,000 PSI. New developments are ongoing to expand the wellhead capacities to 20,000 PSI pressures and temperature up to 400°F (~200°C).

3.4 Trees

Generally today's subsea tree (XT) design is divided into two main concepts; horizontal trees or conventional Dual Bore trees (see Figure 3.5). Due to design limitations w.r.t. production tubing size for Dual Bore trees, the focus has been on the development of new vertical trees with same production tubing bore (7" tubing) as used for horizontal trees. Note that latest development of vertical trees is not synonymous with previous term *vertical dual bore* tree.

A goal is to reduce the building height from wellhead to BOP interface on the top of the tree in order to reduce wellhead fatigue and the height of the template protection structure. This is important to reduce loads during the drilling operations (drill through the tree), completion operations (install or replace completion tubing) or during workover operations (well maintenance). E.g. for a vertical tree system the BOP sits on top of the wellhead during workover and installation of production tubing while it sits on top of the XT for the horizontal system. Thus the weight of the XT and the increased height for the BOP causes more strain on the wellhead for the horizontal system. However the horizontal system has the production tubing landed in the XT and not in the wellhead as for the vertical system and this adds some compensation of stiffening and has to be accounted for.

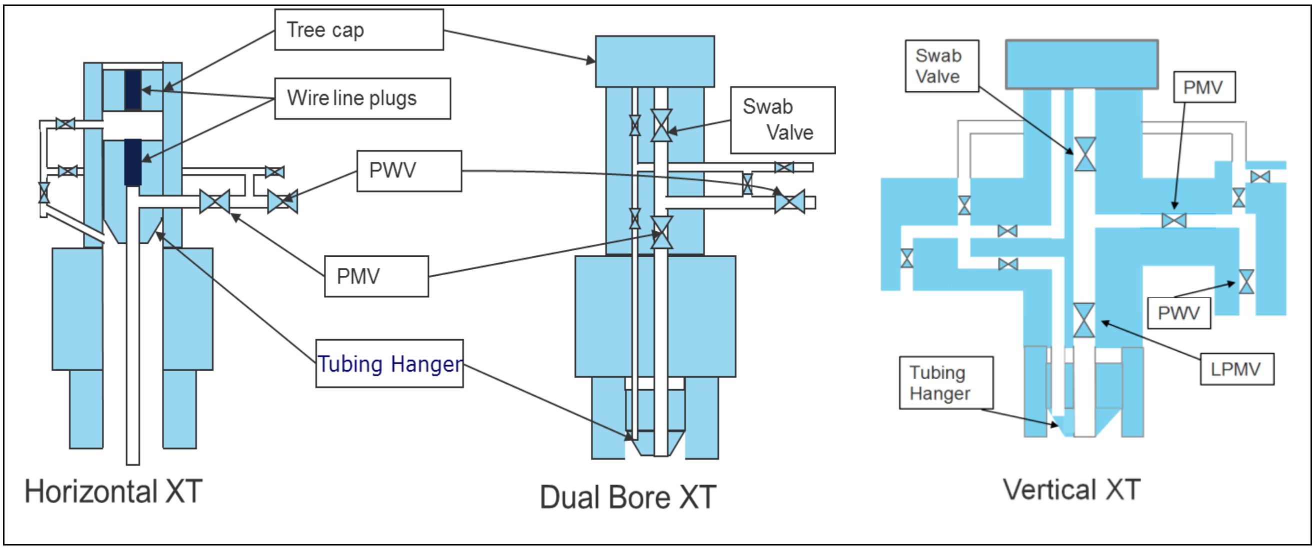


Figure 3.5 Schematic of Horizontal, Dual Bore XT and Vertical XT.

For the NCS there has been a tradition for using horizontal XT's (HXT). Since they became available to the industry in the mid-nineties they have dominated the subsea fields in Norway. Some operators have been hesitant to using HXT and have been using the conventional dual bore tree concept instead. Today, it is apparent that the Dual Bore tree or a vertical tree has its renaissance in the industry. Most suppliers are now developing vertical trees with the same capabilities that have over the years been developed for the HXT concept. The selection criterion for choosing vertical or horizontal concepts varies with regions.

The capability to provide large bore production tubing has given a preference for HXT. As said above, elements as building height, weight and installation efficiency is amongst selection criterion. Installation efficiency is dependent on how the subsea architecture is selected. Since the architecture varies with geographic regions, this is also to some extent the reason for why the tree concepts seem to have regional preferences. Some regions have an architecture better suited for batch drilling, batch installation of trees and batch production tubing installation. Another selection criterion may be existing tool-pool that makes changing concept to be a hurdle.

The evolution within tree design over the years has resulted in bigger and heavier units. Especially the weights starting to be a practical problem due to limitation in crane capacities for handling and installing the trees. A ball park figure for the weight of the tree was previously about 30 tons. Today trees can have a weight up to 70 tons. The increased weight is driven by different factors such as larger 7" production bore and valves, multiphase meters combined with a Flow Control Unit including the subsea production choke. Standardized interfaces to Subsea Control Modules (SCM) and other receivable parts also drive size and weight.

From a production point of view there is a desire to know more and with better precision what is flowing through each well. This in combination with multi zone production control and monitoring creates new functions that have to be accommodated by tree design. This significantly drives the size and complexity to the tree.

Figure 3.6 and Figure 3.7 shows the historical number of flowing wells and the types of trees on the NCS.

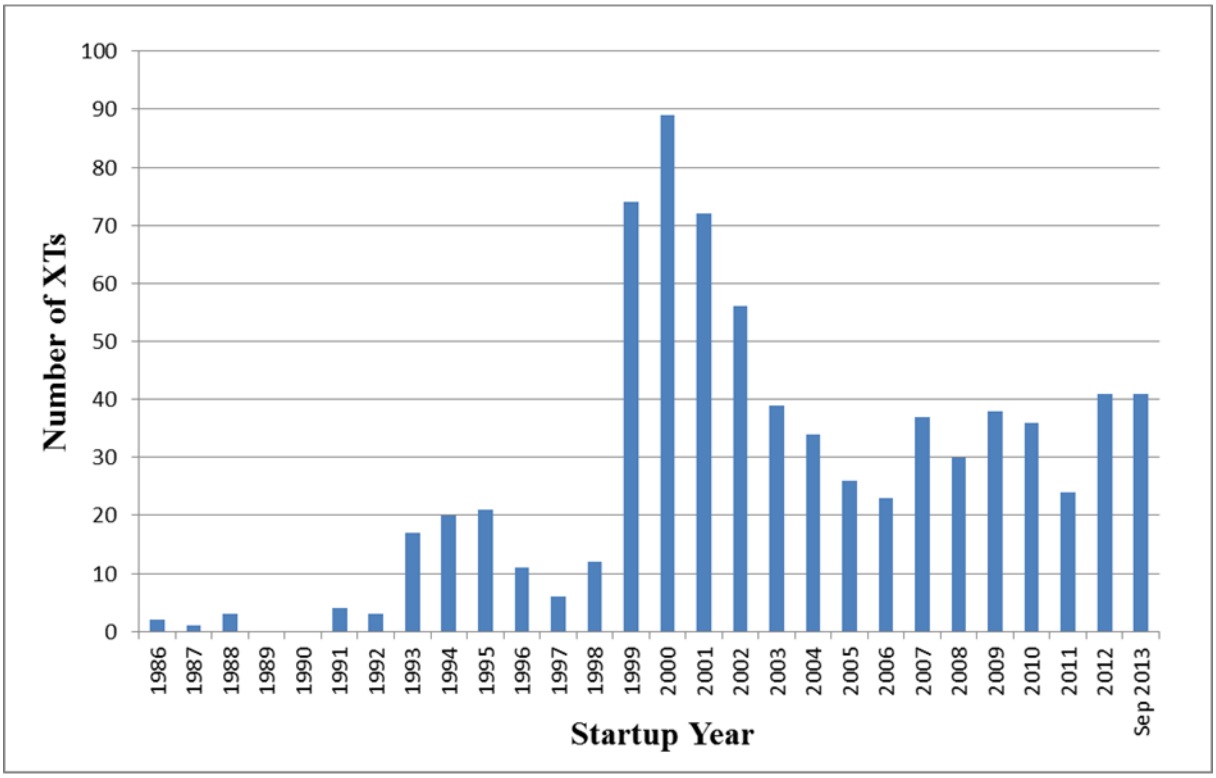


Figure 3.6 Number of flowing wells as function of start-up year, NCS /27/

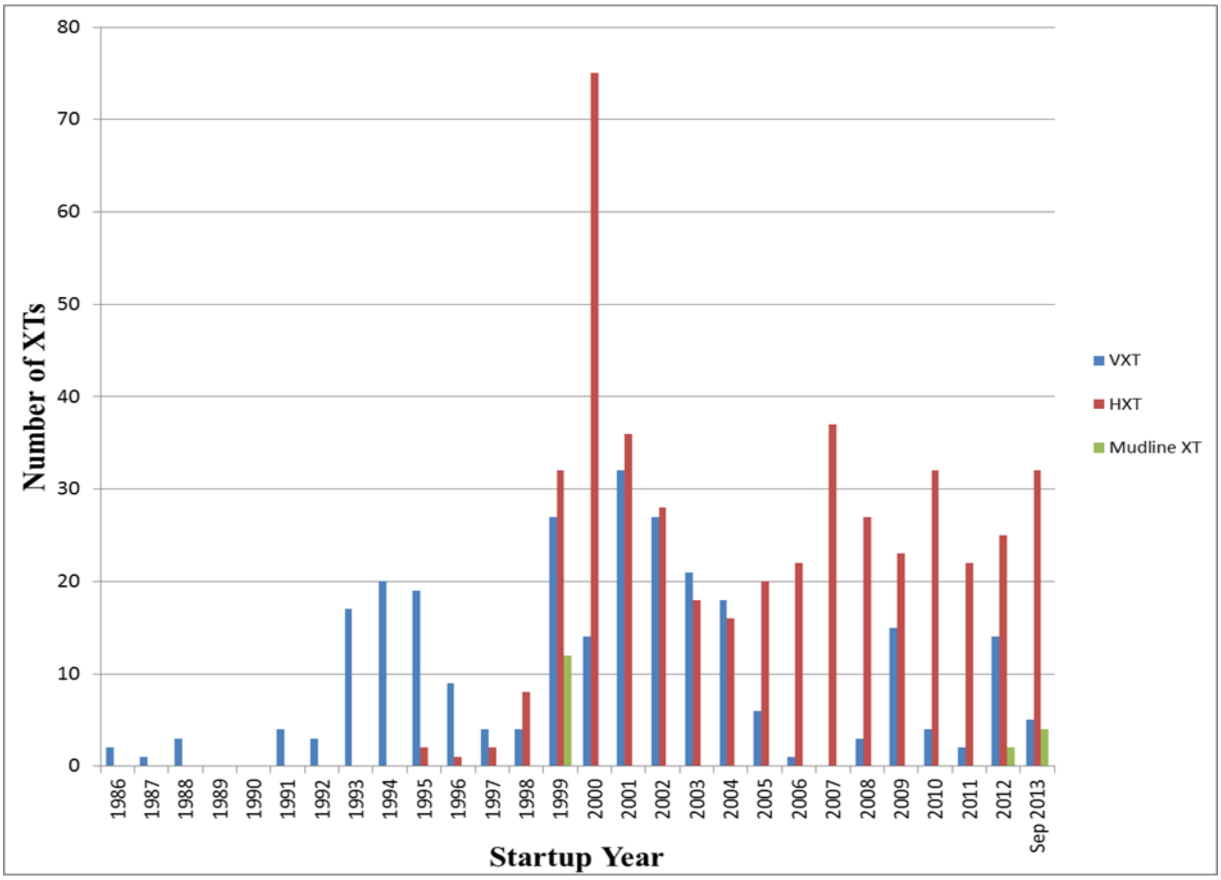


Figure 3.7 Number of flowing VXT, HXT and mudline XT as a function of start-up year, NCS /27/

3.5 Connection systems

On the NCS, the majorities of the subsea fields consist of compact template/manifold solutions. This has also influenced the design of tie-in equipment. In order to reduce building height and the overall footprint on the seabed, there is a preference of having horizontal connections compared to vertical connections.

In typical deep-water application (without overtrawling requirements) the tie-in spools are lowered from above and the entry hub is therefore oriented in a vertical direction (even though guide and hinge-over systems utilize horizontal connectors). Quite often the connector make-up tool is already installed on to the connectors of the tie-in spool prior to launch. These vertical systems usually need a goose neck with bend restrictors for flexible flowlines or additional bends in a ridged flowline to provide enough flexibility to handle thermal expansion and fabrication tolerances. Such designs can tend to be quite tall making them less attractive for the NCS. Figure 3.8 shows typical vertical and horizontal connection systems.

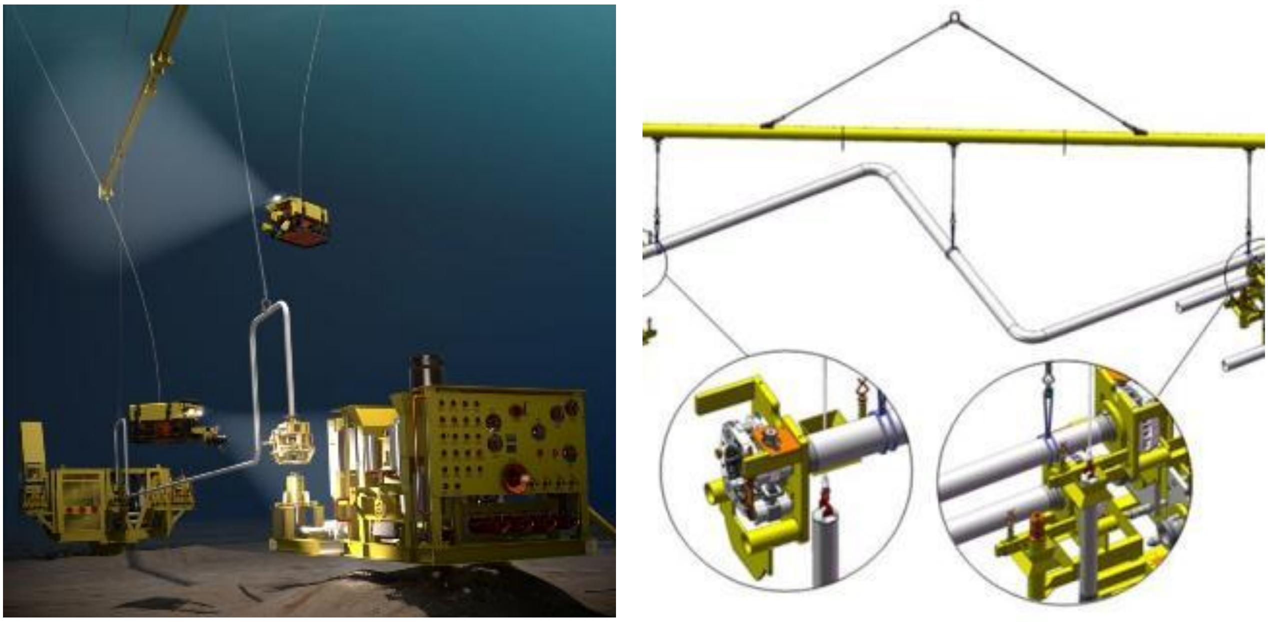


Figure 3.8 Vertical and horizontal connection systems (Image: Aker Solutions)

3.6 Control and Instrumentation

Over the years the traditional developments have had instruments for pressure and temperature monitoring of the produced fluids located on the tree. The integrity of the production tubing is evaluated by monitoring the pressure between the production tubing and production casing through sensors located in the XT. For the production path, instruments are normally located down-stream the production master valve. Very little instruments have been installed in order to monitor the condition of the equipment itself. The control system (multiplexed hydraulic electric systems) has the possibility to monitor the status of the solenoid pilot valves in the SCM. The condition of the electrical supply through the umbilical is monitored from the topside Electrical Power Unit.

Today the subsea trees and manifolds are getting more instruments and are also often equipped with a multiphase meter which is getting more popular as they have become more accurate and reliable in operation. The multiphase meters have been installed for better production optimization and to some extent for production allocation when different Operators are producing through same infrastructure to the processing unit.

The industry has gone through several steps with regard to operating valves starting with diver operated valves, then direct hydraulic control to today's electrohydraulic multiplexed control system which is the norm in the subsea industry. Electrical actuators for all electric trees have been discussed for a long-time but seem to struggle to be accepted in the market. However, a few numbers of systems have been installed or are in the process of being installed on subsea compression facilities where actuation speed and number of cycles are critical. With the introduction of subsea processing facilities, there will also be an increased need for electric power to operate electric motors and separator systems and their control systems. Also Direct Electric Heating (DEH) of pipeline is becoming more popular which requires large amounts of power.

There is ongoing work to enhance the hydraulic system by developing hydraulic power units that are located on the seafloor instead of on a platform. This will significantly reduce the number of hydraulic control lines in the control umbilical or potentially eliminate them altogether and thus significantly reduce the cost and complexity of these. It can also increase the maximum step-out distance for hydraulic control systems. This solution can also be of interest for the retrofit or brown-field market.

For signal transmission the industry is moving from communication using copper wire to fibre optic cables due to the massive increase in transmission capacity and speed. Components for fibre optic signal transmission as the fibre and connectors have been available for many years but some are still not confident with regard to the reliability. Minimum bending radii is still a bottle neck in order to design space efficient systems to get the fibre signal into the well for down-hole sensors. There are also challenges related to the reliability of wet mating of couplers with fibre optics.

In general good international standards regarding the engineering of modern subsea control and instrumentation systems is lacking. ISO 13628 has not kept up with advances in technology and is not sufficient for the more complex developments in subsea processing. The subsea industry should consider adopting an analogy to IEC/EN 62061"Safety of machinery: Functional safety of electrical, electronic and programmable electronic control systems", when developing control systems for the modern subsea processing systems.

3.7 Workover Systems

Workover systems are outside the scope of work for this report however, workover systems solutions will impact choice of tree design. Workover systems can be categorized in different ways, but one important differentiation between systems is landing string systems versus open water systems utilizing Lower Riser Packages (LRP), ref. Figure 3.9. By tradition landing strings have been based on rental pools owned and maintained by the manufacturer (typical manufacturers are well testing companies as Schlumberger and Expro). This has led to landings strings being universal and necessary interfaces to different tree manufactures system are relatively few. Also those systems are easily configured to operate inside BOPs of different make and configurations. For open water solutions and LRP systems there has been a tradition that such systems are being procured by operators, and also being designed and engineered by the subsea contractors. A new trend now is that supplier independent (universal) workover systems are being developed for open water systems as well. A driver today is that well maintenance or well work over operations is costly and access to the well bore is less available compared to platform wells. In order to release the recovery potential for an increasing number of subsea wells there has been a drive to develop more efficient methods and technologies in order to increase the efficiency of work-over wells.

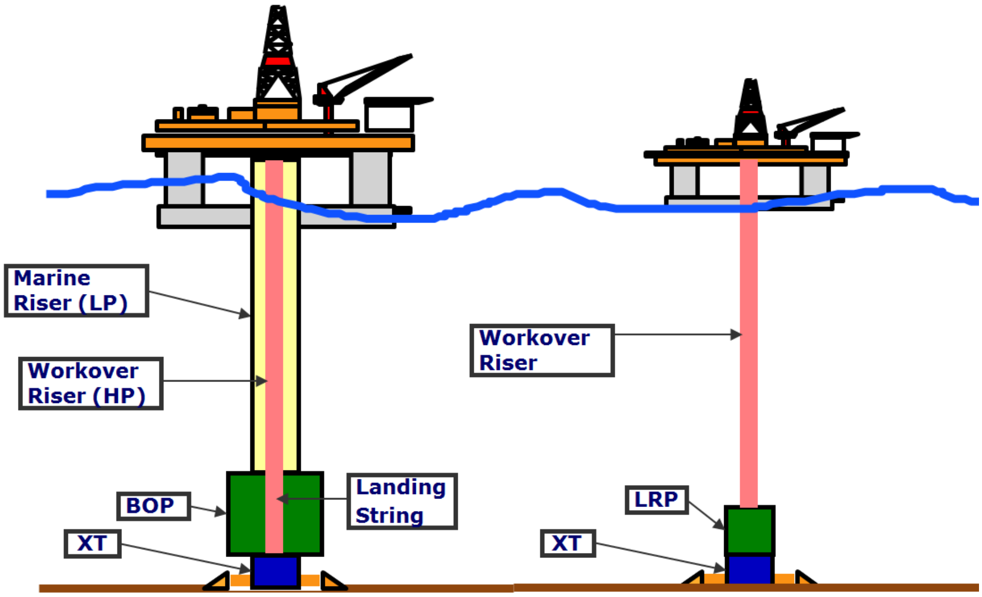


Figure 3.9 Workover Systems, Heavy Workover Landing String (left) and Open Water Workover, LRP System (right)

3.8 Subsea process and boosting

Over the years subsea processing has been mentioned as the future of oil and gas production. The motivation for subsea processing has changed, from reducing topside weight, to being an enabler for late life production till today where subsea process facilities have been installed on green field developments. Increasing the oil recovery is a key driver. An additional benefit with doing the processing subsea compared with topside or onshore includes reduced cost, optimised production and reduced HSE risks. Furthermore, producing fields with heavy oils and/or low reservoir pressures might become feasible if installing subsea processing equipment. Figure 3.12 shows a global overview over the subsea processing systems.

In the early 1990's the Kværner Booster Station (KBS) was build and tested but never used in actual production. Then it was followed by the subsea separation projects Troll Pilot and a decade later Tordis which were installed on NCS. **Tordis (2007)** was the world's first full-scale commercial subsea separation, boosting and injection system (ref Figure 3.10). It was designed to remove water and sand from the well stream and re-inject it into a nearby formation. A multiphase pump was installed to assist in transporting the oil and gas to the topside facility.

Figure 3.10 Tordis - the world's first full-scale, commercial subsea separation, boosting and injection system

The **Perdido (2010)** and **Pazflor (2011)** fields were the first full field subsea separation and pumping systems in their respective regions. Both involve vertical gas/liquid separation units, whereby the gas free-flow to the topside host and the liquid mixture is boosted by means of subsea pumping.

The **Marlim field (2011),** which is the world's first system for deepwater subsea separation of heavy oil and water, installed a horizontal pipe separator especially designed to separate oil from water. The water is re-injected for reservoir pressure support, while the oil and gas are commingled downstream the separator station and free-flow to the topside facility (see Figure 3**.11**).

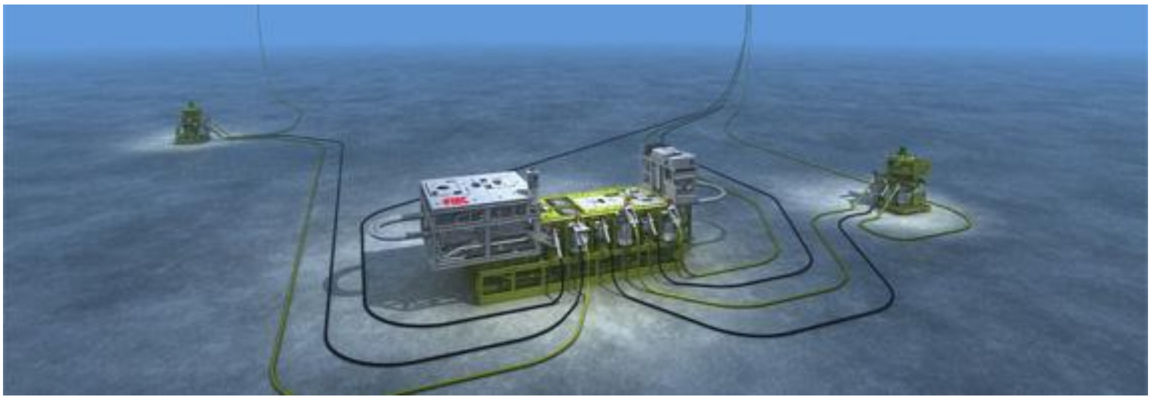


Figure 3.11 Petrobras Marlim - Oil and Water Subsea Separation. Brazil, Campos Basin. Image: FMC Technologies

The global subsea industry (particularly Brazil) has today considerable experience with Electro Submersible Pumps (ESP) located down in the well but this technology have not yet been utilized on the NCS.

Today (2014) there are three major projects ongoing with subsea compressor stations. Two are in its project phase (**Gullfaks** and **Åsgard**) while the third is still to be sanctioned (**Ormen Lange**)(February 2014). Those units will by far push the limit of complexity of equipment and systems to whatever have been installed on the seabed before. They are all being installed on mature fields with the purpose of increasing the production.

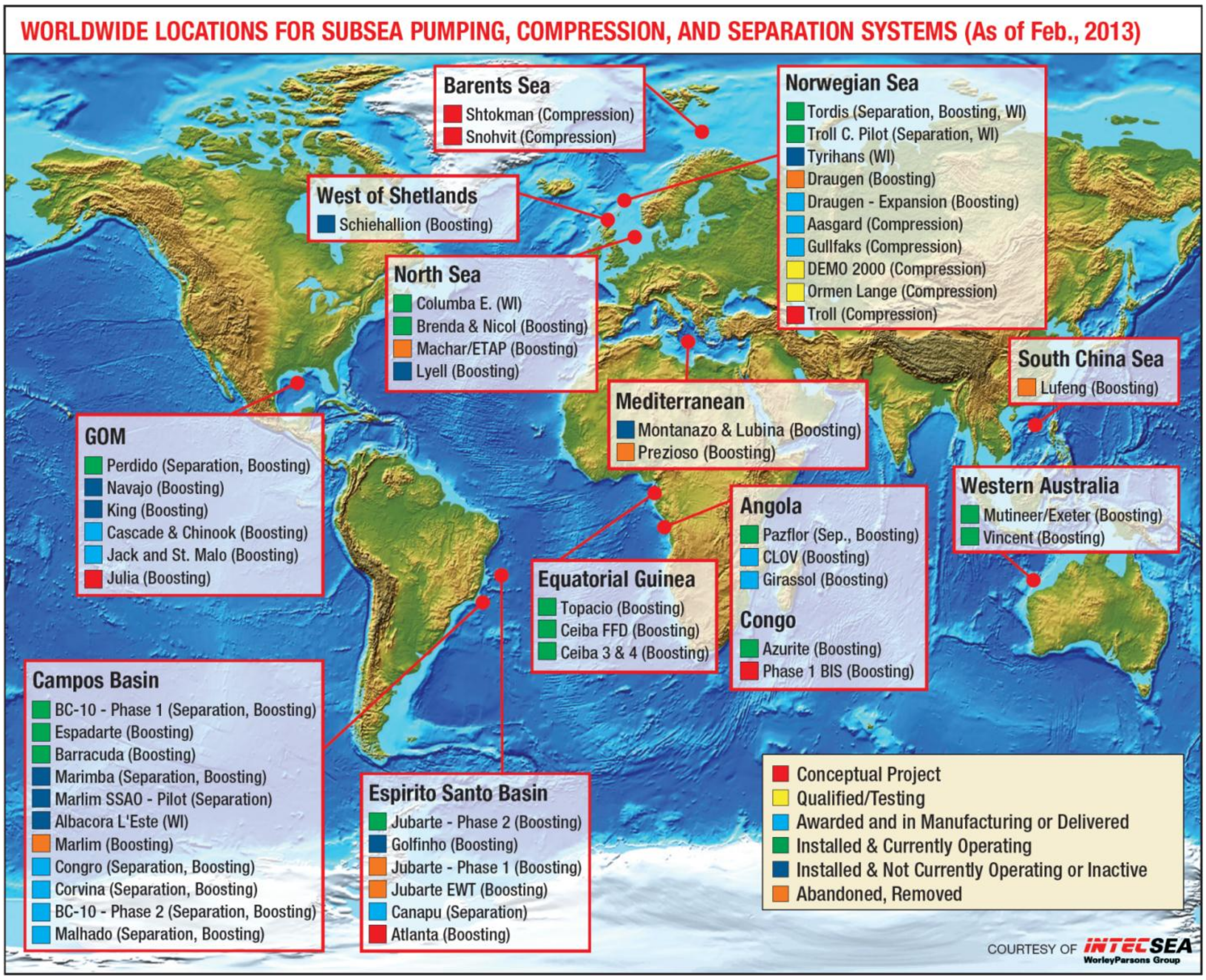


Figure 3.12 Worldwide locations for subsea pumping, compression and separation system (As of Feb., 2013). Acknowledgment to INTECSEA and 2013 Offshore Magazine poster /39/

3.9 Umbilical

An umbilical can provide hydraulic and electric power to the control system, chemicals for injection into well or production system, electric or fibre optical communication, electric power for pumps or gas for gas lift.

The umbilical is a tailor made product that depends on the complexity of the system. Tube material for shallow water can be thermoplastic which has good fatigue resistance, short delivery time and is low cost. On the other hand it has limitation when it comes to chemical compatibility and use in deeper water. Since the development is moving in the direction of deeper water and higher pressure and temperatures, steel tubes are now dominating. The most common material used for fabrication of umbilical tubes, both on NCS and in the rest of the world, is 25Cr duplex stainless steel. This material has excellent corrosion properties, high strength and good fatigue properties. Other types of Duplex materials are being presented from time to time, such as Lean Duplex 19D and Hyper-duplex.

There is an undefined borderline of when to use an umbilical versus a power cable. Significant research these days go into materials and materials behaviour in dynamic application, and then most w.r.t.

electrical conductor material and water shielding. A technology driver for power cables is to push the limits for voltage and power levels for dynamic deep water application. Also the industry today lacks good standards for electric power transmission and distribution. In this way the umbilical is also subjected to this dilemma of qualification through standards when it is transmitting power for high consumers, i.e. subsea boosting and multiphase pumps. For higher power consumers as compressors there will be a separate power cable and the umbilical will not be used for power transmission.

In addition there is a trend for more use of electric motors and electric actuated valves and this will also have impact on the umbilical design. The hydraulic tubes can be replaced by electric cables and methanol and MEG lines may be replaced by large DEH cables or locally stored chemicals.

3.10 Template and manifold

As mentioned in previous sections, the motivation to design templates and manifolds varies with geographies. An important driver to select integral templates with manifolds is to reduce number of units installed on seabed as well as limiting the physical footprint in order to allow for a cost effective protection design. This leads to several functions that the template shall achieve such as;

- Provide guide and hang-off of the conductors and wellhead in order to support drilling of the wells
- Bottom foundation structure to carry the weight of the manifold module to avoid settling
- Support tie-in of umbilical and export- or injection-pipeline
- Support Subsea Distribution unit and control system accumulator banks
- Support for Manifold Control Module (MCM)

In regions exposed to fishing gear, or dropped objects, protection is required and protection structures will often be an integrated part of the template structure.

Today the trend is to have a modular design in order to reduce design and manufacturing time and thus allowing shorter delivery and installation time. This allows drilling to start earlier for the operator thus allowing multiple activities to go on at the same time. These solutions will normally be more attractive when multiple manifolds are ordered. This will enable interchangeability of equipment which provides flexibility and minimize risk of misfit when the manifold is landed on the template. Modular design is also motived to make the manifold relatively efficient to retrieve if this should be required. However, it is very rear that the manifold needs to be retrieved.

Modularization of the subsea station is also a question of balancing what functionality that is built in to the system versus complexity and lifetime cost. It is today common that the choke is located on a separate module together with a multiphase meter if that is installed. This unit is normally referred to as the Flow Control Module (FCM) or a Choke Bridge Module (CBM). This module contains the components that are likely to require service and are located together for efficient retrieval. In this case neither the tree nor the manifold will have to be retrieved. Another important aspect is to design the system with sufficient number of barriers such that one XT can be retrieved while the other XTs continue to produce.

Flexibility is a valuable feature in any subsea system and allows the operator to adapt to changing operating conditions, reduce the production loss when equipment is not working properly or to connect future subsea wells / tie-back. The manifold is a key element to enable this. In some areas it is common to have dual header manifolds connected to two parallel pipelines. With this configuration the same manifolds can for example be used for injection purposes at the same time as it allows for production or continue production while performing pipeline maintenance. By having header in same dimension as the pipeline, and with introduction of a pigging loop the operator will be able to launch/receive the pig from the same platform. This makes the pigging operation much more efficient and less costly. Figure 3.13 shows a field layout illustrating a roundtrip piggable solution and one solution that requires launcher or receiver to pig the flowline.

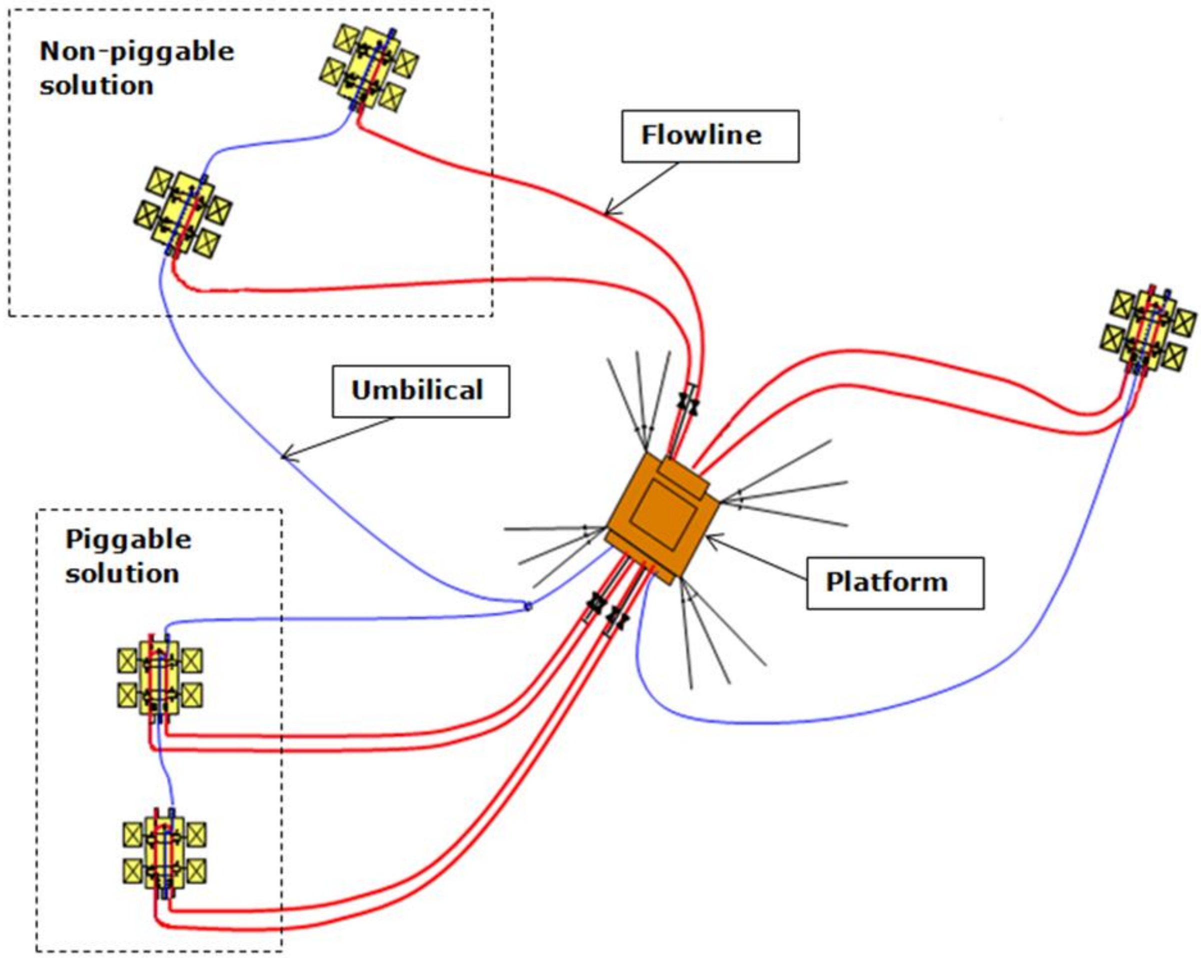


Figure 3.13 Field layout illustrates roundtrip piggable solution and one solution that requires launcher or receiver to pig the flowline.

4 OVERVIEW AND OUTLOOK – NCS AND GLOBALLY

In this section there will be an overview of subsea installations in a global perspective. The sources to compile this information are detailed in this section.

4.1 Equipment databases

Different available public sources and databases for where information about installed subsea facilities can be extracted exist. Table 4.1 shows the most commonly used databases/sources of information used by the industry. Typically used for market strategy and planning.

- Quest Subsea Database
- Subsea UK, Project Database
- Infield, Offshore Energy Database Subsea Completions
- Subsea IQ
- The Norwegian Petroleum Directorate (NPD) - Fact Pages

A short description is given Table 4.1.

Table 4.1 Databases and open sources covering installed subsea equipment

Info about provider	**Description**
Quest Offshore	**Quest Subsea Database /27/**
- Offers the following services: ▪ weekly and monthly newsletters ▪ real-time web-based access to detailed data - The products are focusing on the key markets involved in the deepwater oil & gas industry - Quest Offshore Resources is based in Houston	- The database gives information about global subsea projects - Historical data goes back to 1961 and the forecast data is to 2016 and beyond - Projects are divided so that information can be found about each XT or control module that is included in the project - Information about operator, province, start-up year, tree classification, tree location among others are available - Provides forecast analyses and a market overview /27/

	Subsea UK, Project Database /31/
- Subsea UK was established by the industry and acts on behalf of the industry - Aims to ensure that UK maintains its position within the subsea market - Subsea UK is located in Aberdeen	- The database catalogues information about worldwide subsea projects - Gives information about location, operator, water depth, number of subsea wells, manifolds, pipelines and umbilicals
	Infield, Offshore Energy Database Subsea Completions /36/
- Infield Systems Limited is provider of business intelligence, analysis, transaction support and research to the oil, gas, renewable energy and associated marine industries - Headquarter in London	- The Subsea Completions data set has information containing subsea satellite wells, template wells, manifolds, templates and subsea processing units, currently operational or being planned or considered for development
	Subsea IQ /29/
- Subsea IQ is a site that started in 2007 - The site is a division of Rigzone, international web site for the upstream oil and gas industry - Headquarter in Houston	- Subsea IQ provides general information about field and developments worldwide. - There is little information about subsea components and to get the available information you may have to go through different articles that describe different activities for the field. Articles can describe the discovery of the field, if the field have been further developed, change of operator etc.
	The Norwegian Petroleum Directorate (NPD) - Fact Pages /34/
- NPD is a governmental specialist directorate and administrative body - NPD was established is in 1972 - Headquarter in Stavanger	- NPD FactPages contain information regarding the petroleum activities on the NCS - Information about field, current status, type of subsea equipment (single well template, multi well template) etc.

4.2 Summary of results from equipment databases

The databases show that the number of subsea wells has increased considerably over the last years. This exact number may vary depending on the source of information.

Quest Subsea Database /27/:

According to Quest /27/, the numbers of flowing subsea wells is approx. 5 000. The number has increased considerably over the last 15 years as can be seen in Figure 4.1.

Figure 4.2 shows number of flowing XTs for different geographical areas. Figure 4.3 shows type of flowing XTs in the same geographical areas (see chapter 3.4 for details).

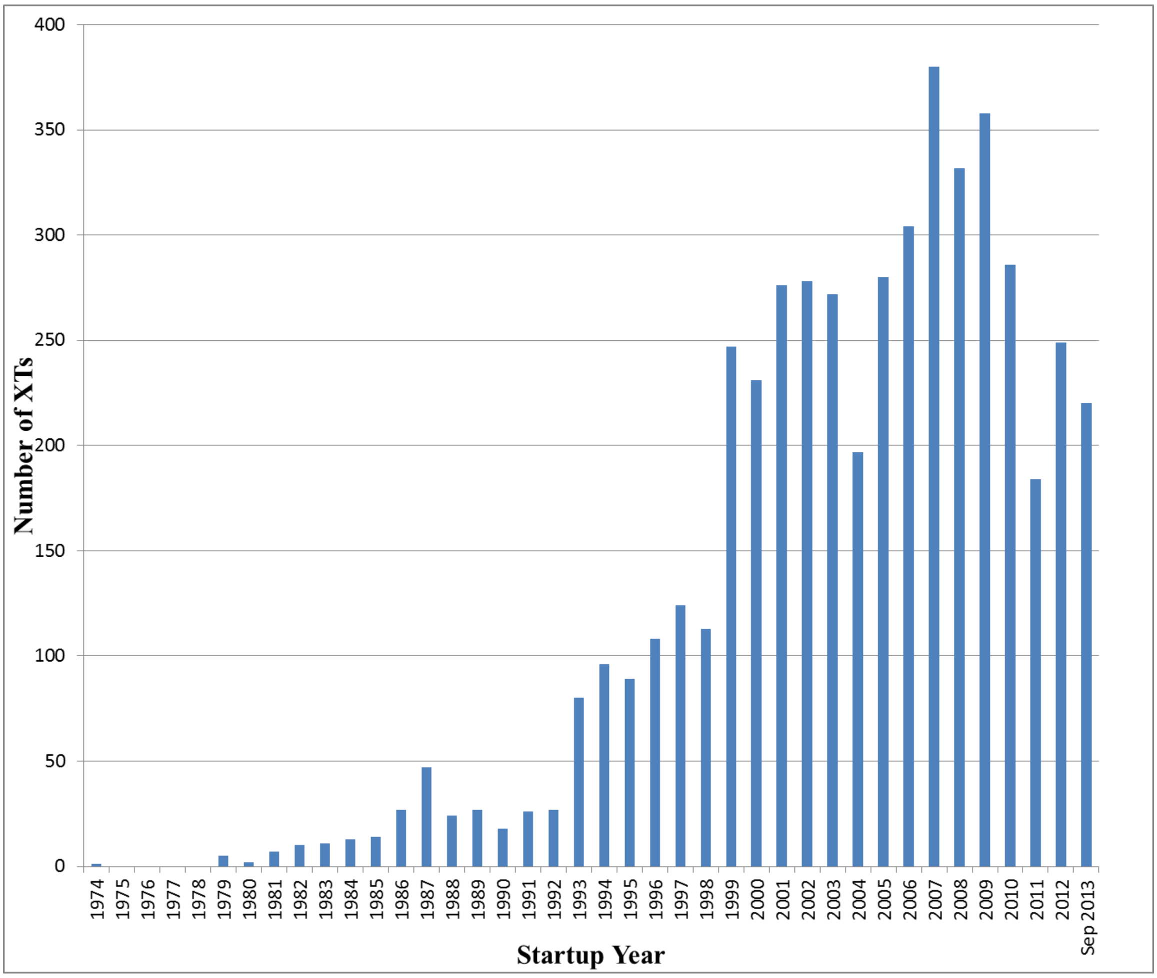


Figure 4.1 Flowing XTs as function of start-up year, World Wide /27/

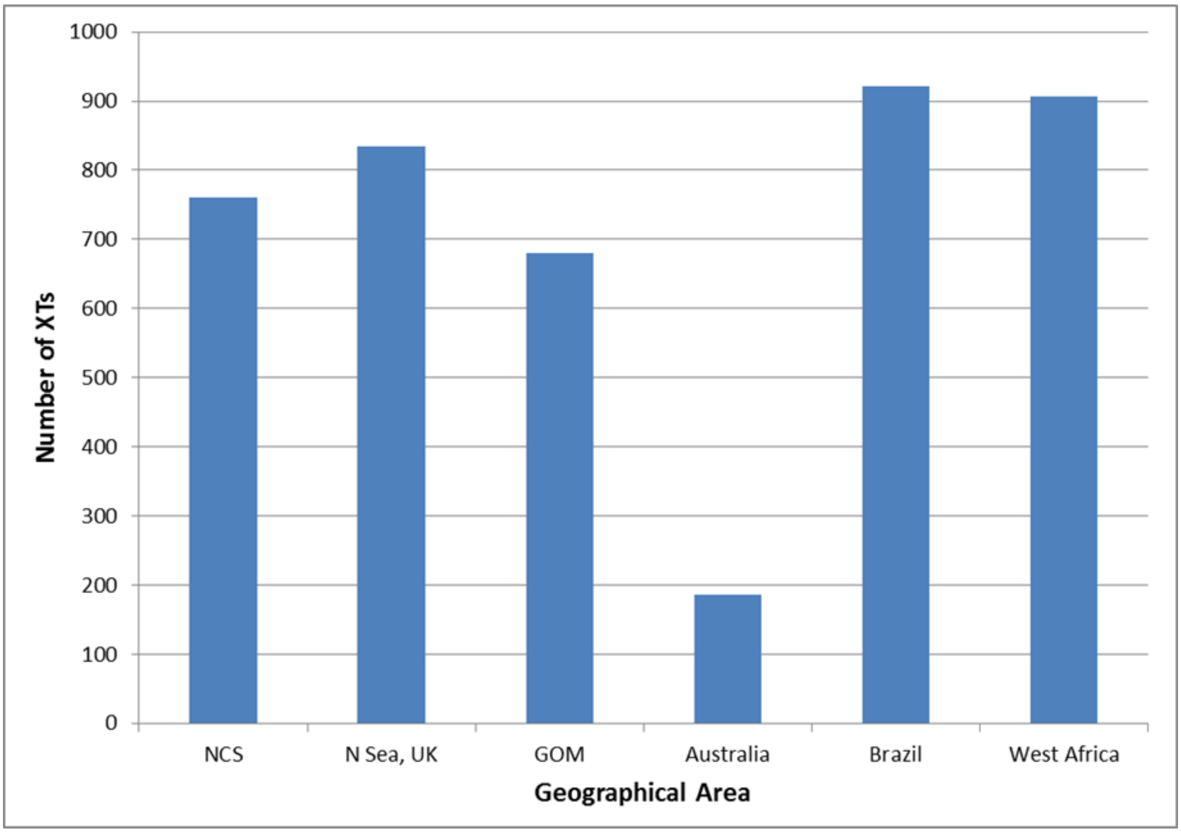


Figure 4.2 Flowing XTs for different geographical area /27/

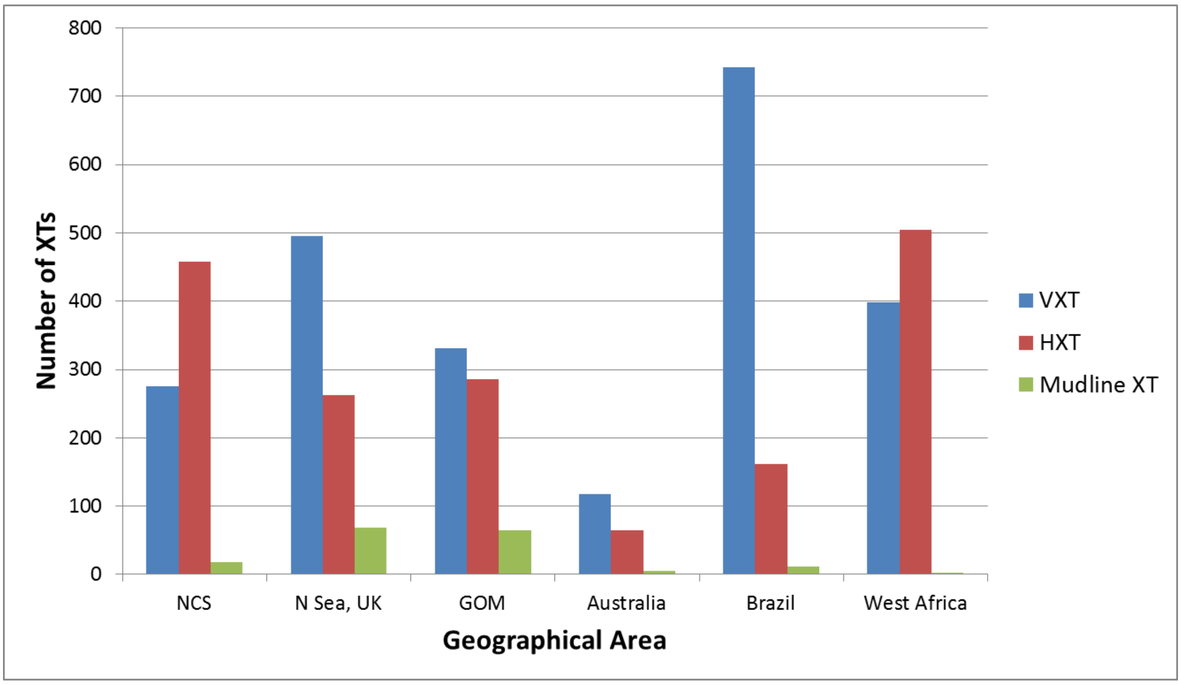


Figure 4.3 Flowing HXT, VXT and mudline XT's for different geographical areas /27/

The subsea solutions can be divided in how they are tied back. The graphs indicate this versus number of tree installations. The Figure 4.4 shows information about host type for all geographical areas and Figure 4.5 shows information for NCS. Fixed production and land are quite straight forward and include fixed platform and XTs that are tied into land. The floating production includes XTs that are tied in to a FPSO, FPS-Semi, TLP, Spar, compliant tower, FPU, FSO and FPDSO. The XTs that has the Host Type Manifold doesn't have a floating platform, fixed platform or other host types in the same project and is tying into a manifold slot on a different subsea project. The XTs that are tied in to a host type that is not mentioned above is sorted under other.

The Figure 4.4 and Figure 4.5 shows that the largest number of subsea installations is tied in to floating production vessels. About twice as many XTs are tied in to floating production compare to fixed platforms. The worldwide distribution and distribution for NCS show similar trends.

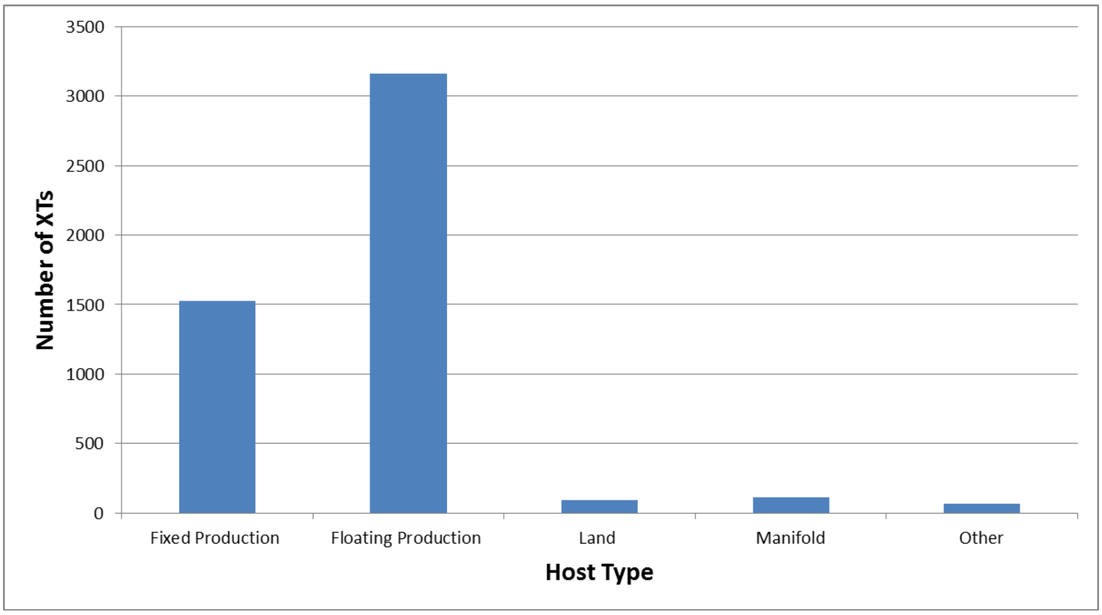


Figure 4.4 Number of flowing XTs divided by Host Type, World Wide /27/

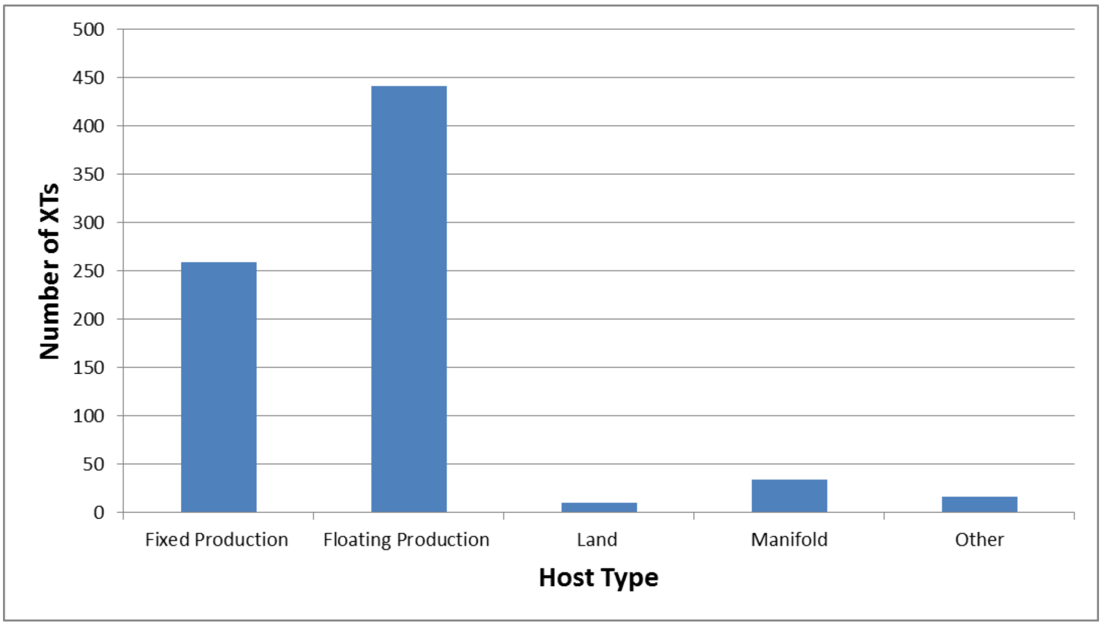


Figure 4.5 Number of flowing XTs divided by Host Type, NCS /27/

Infield, Offshore Energy Database Subsea Completions /36/:

Infield Systems published a Subsea market report in 2013 which describes the global subsea trends towards 2017 /36/. The trends in global growth are presented below.

Latin America and West Africa account for over half of subsea capital expenditure (CAPEX) expected to be spent between 2013 and 2017. This is driven by large deepwater and ultra-deepwater discoveries offshore Brazil, particularly in the pre-salt basins, and offshore Angola and the Gulf of Guinea. As an operator, Petrobras dominates the subsea sector.

The highest investment levels and number of installations of subsea trees in Africa are expected to occur in 2017 driven by large developments in Angola and Nigeria. Simultaneously, emerging countries such as Ghana, Congo-Brazzaville and Equatorial Guinea are expected to increase their presence in the subsea sector.

As mature regions, **Europe and North America** still present significant opportunities for the subsea sector. Norway and the UK are characterised by high drilling activity on producing fields and the completion of subsea tie-backs on smaller, remote accumulations mostly in shallow waters. In the North Sea, this is linked to efforts to reverse declining oil and gas production. Despite a decrease in global CAPEX market share due to less capital intensive shallow water activity relative to other regions, Europe is expected to attract an increasing share of subsea tree installations.

In the **USA** the shift from shallow water developments where production is in decline towards large oil and gas discoveries further offshore is well underway. The deepwater Gulf of Mexico is expected to host many new floating platform developments, combined with the tie-back of subsea satellite fields later on in the forecast period.

Asia, Australia and the Middle East present emerging opportunities for the subsea market. These three regions are expected to increase their market share in the years to come. Operations in Asia are increasingly moving exploration and production into deeper waters in a bid to boost and sometimes reverse declining oil and gas production. As a result, Malaysia, Indonesia, India and China are becoming major subsea industry hot spots attracting a range of operators: from NOCs, CNOOC and ONGC, to IOCs Shell and Chevron and independent international companies like Murphy and Husky.

Australia subsea sector is driven by its fast-growing LNG export industry, which is racing to meet rising demand for natural gas in emerging Asian economies. Fields such as Chevron's Gorgon area fields are being tied back to large onshore LNG producing facilities.

New large gas discoveries in the last five years in the **Eastern Mediterranean** are also driving subsea investments in the Middle East region. The start-up of the deep water Tamar field in April 2013 offshore Israel is expected to be only the start of increased subsea activity in the Levant Basin.

5 INCIDENTS

Uncontrolled release of hydrocarbons may have serious consequences. Other fluids, as e.g. control fluids and chemicals, from subsea installations may have impact on the environment in form of pollution and on the operability of the installation.

The safety authority and/or environment authority in the relevant countries require that all accidents and leakages are reported, and they aim at developing and maintaining various statistics for all accidents and incidents. In addition, there are also other institutions and organisations that collect and systemize data for incidents. Some of these public available databases have been looked into in order to see if there are any significant trends for uncontrolled releases from subsea facilities to see what information that can be retrieved from these databases.

5.1 Incident and accident databases

Similar to the facilities- and well-databases there are databases that compile information about incidents and accidents in the subsea industry. Table 5.1 gives a short description of the most common public available databases.

The PARLOC database is not included herein since it covers information related to pipelines and pipeline components and not subsea equipment. Further, since the information in the CODAM database is not updated continuously and thus details regarding the various reported incidents may be incorrect, it was decided to include the "Hendelsesdatabasen" and not CODAM. According to PSA, "Hendelsesdatabasen" gives more updated and correct information regarding subsea leakages on NCS.

Table 5.1 Key databases for accidents and incidents

Info about provider	**Description**
	**WOAD – Worldwide Offshore Accident Databank /33/**
- The most comprehensive available data source for offshore risk assessment and emergency planning - World Offshore Accident Database is operated by DNV GL	- WOAD contains more than 6000 events from the period 1970-2009 - The data is mainly delivered from public domain sources such as official publications and reports, newspapers, data available from authorities etc. - Information about accident date, geographical area, type of unit, main event etc. is given for each accident - Limitation on how detailed the accident description is and the availability of incidents that actually have occurred in some geographical areas - The database is publically available for an annual fee

OREDA /37/	
- OREDA is a project organisation sponsored by 8 worldwide oil and gas companies - The purpose is to collect and exchange reliability data among the participating companies and act as The Forum for co-ordination and management of reliability data collection within the oil and gas industry	- OREDA has established a comprehensive databank with reliability and maintenance data for exploration and production equipment from a wide variety of geographic areas, installations, equipment types and operating conditions - Main focus is offshore subsea and topside equipment, but onshore equipment is also included - The OREDA data are stored in a database. Specialized OREDA software has been developed to collect, retrieve and analyse the information - The information contained in this database is not public information
PETROLEUM SAFETY AUTHORITY NORWAY **"Hendelsesdatabasen" /38/**	
- The Petroleum Safety Authority Norway (PSA) is an independent government regulator with responsibility for safety, emergency preparedness and the working environment in the Norwegian petroleum industry	- The database covers information about leaks of hydrocarbons and control fluids on NCS - Based on the available information it is difficult to reveal the root cause of accidents
Health and Safety Executive HSE **HCR - The Hydrocarbon Releases Database System /1/**	
- Health and Safety Executive (HSE) is a non-departmental public body of the UK - It is the body responsible for the encouragement, regulation and enforcement of workplace health, safety and welfare, and for research into occupational risks in England, Wales and Scotland - The data contained in the HCR System database is owned by the duty holders and volunteered	- The Hydrocarbon Releases (HCR) System contains detailed voluntary information on offshore hydrocarbon release incidents in UK - Dating from 1 October 1992, on all offshore releases of hydrocarbons reported to the HSE - The leaks can be sorted out and information about e.g. quantity and equipment can be found - The database involves some information about root cause of accident - The database is continuously being updated and the latest information is today from April 2013 - The available data for leaks from subsea facilities is limited since it does not differentiate between accidents topside or subsea - Access to the full system is by authorized persons only, however, free on-line published HCR data may be available

Bureau of Ocean Energy Management, Regulation and Enforcement	**BSEE - Bureau of Safety and Environmental Enforcement /35/**
- BSEE is an agency under the United States Department of the Interior - BSEE is responsible for safety and environmental oversight of offshore oil and gas operations, including permitting and inspections, of offshore oil and gas operations - Formerly under the Minerals Management Service (MMS)	- The BSEE site contains accidental statistis for accidents in the Outer Continental Shelf (OCS) - It is difficult from the available information to identify whether the accident has happened topside or subsea

5.2 Information extracted from incident databases

Incipient hydrocarbon releases are potential precursors to major accidents. It is considered highly important to establish the root cause, and the trend, when accidents or incidents happen. This is to enable the implementation of correct actions to prevent future incidents and to enable the industry making the mind and technology shift necessary to deal with it in a long term perspective.

In the search for information on the largest accidents and release of hydrocarbons from subsea facilities, public sources from the national safety authorities have been sought after and reviewed. The content of these sources varies and clear information on volumes, type of leakage, root cause etc. is not easy to retrieve. However, the information in the databases shows that releases from subsea production systems are relatively few and small compared to releases from other activities e.g. installation, work over and drilling. The reviewed statistics are based on;

- PSA "Hendelsesdatabasen" (Incident database)
- Bureau of Safety and Environmental Enforcement (BSEE) Statistic for releases in the Gulf of Mexico and the Pacific
- HSE supplies data from the British sector

The incidents in this section are based on available information that can be found in the different databases that are presented below. The incidents that have been classified as 'most serious' are described in Section 5.2.5. This covers both hydrocarbon and control fluid releases (release of some controls fluids are part of normal operation (open control systems).The main focus is on incidents at NCS.

The general observation is that the amount of information in the databases is relatively limited, at least what is public available. In addition, it is no information available whether the leakages have occurred due to operation outside the design and/or operation envelope. The information indicates that leakages often occurs when there is a transient situation such as drilling, work-over or other intervention activities.

5.2.1 "Hendelsesdatabasen" (Incident database)

"Hendelsedatabasen" from PSA gives the most detailed description of each incident. The database contains information on which fluid that has been released, from which equipment it was released, amount of release and what type of fluid that was released. Both release of hydrocarbons as well as unintended release of control fluids are registered.

Further, the database includes about 80 leaks from the period 1999 to October 2013. Out of these leaks, 20-25 leaks are connected to error in valves and 8-10 are leaks detected in connection with replacement of retrievable modules (FCM, SCM etc).

The root cause for the leaks is classified by accidents related to design shortcomings, quality issues, leaks during installation / intervention, leaks due to abnormal operation and unknown cause as shown in Figure 6-1. The classification is based on the information that is available in the description of the leak in "Hendelsesdatabasen". The categories 'design and quality' is due to fault that can be related to the design, material or manufacturing. Production causation is a fault due to 'operation' because of abnormal condition. Valve that by mistake has been open or leaks during abnormal ROV operation are examples of leaks that that have operation as the root cause. 'Install/intervention' includes all leaks that have happened during installation/intervention phase. A leakage during change of control module is a typical example of a leak in NCS for this category. If the information in the accident description isn't sufficient to link the leak to one of the explained categories then the cause of accident has been classified as 'unknown'. The cause of accident for most of the accidents is unknown. A conclusion is that the available information in most of the cases is not sufficient to be able to draw any conclusion to the root cause.

The result is similar to the result from the HCR Database given in Figure 5.3.

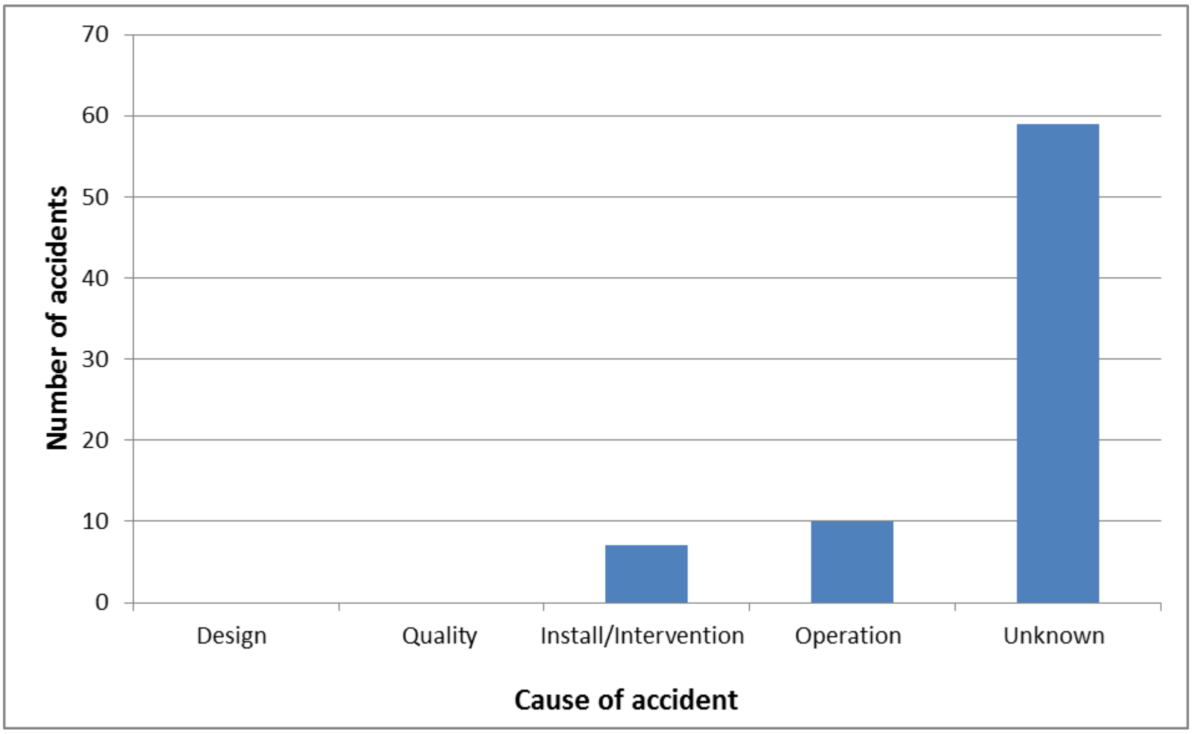


Figure 5.1 Leaks in Norway divided by cause of accident/28/

5.2.2 Bureau of Safety and Environmental Enforcement (BSEE)

The Bureau of Safety and Environmental Enforcement (BSEE) is an agency under the United States Department of the Interior. The Bureau of Safety and Environmental Enforcement (BSEE) carries out investigations on behalf of the Secretary throughout America's 1.7 billion acres of the Outer Continental Shelf (OCS). BSEE incident investigations seek to determine the cause or causes of an incident. BSEE will typically convene a "panel" to investigate incidents that result in death, serious injury, or a significant pollution event.

The investigations reports are comprehensive but you may have to go through many different reports to find information related to subsea. It requires therefore a substantial effort, due to the amount of investigation report, to find information for trending of subsea incidents by this approach. The BSEE site does however have a summary of accidents and incidents where incidents are categories under following categories fatalities, injuries, loss of well control, fires/explosions, collisions, spills ≥ 50 bbls and other. The incidents under the categories spills and loss of well control are of interest for subsea installations. Spill Summaries, OCS Spills ≥ 50 Barrels (1964 – 2012), is available but the spills source is only classified as platform/rig or pipeline and it is therefore not possible to know if the leak has occurred on a subsea facility.

Figure 5.2 below shows the available data for loss of well control in the US sector GOM and PAC. The BSEE only states in which operation modus the incident took place and location. No indication of root cause.

LOSS OF WELL CONTROL ***	2007		2008		2009		2010		2011		2012		2013 ytd	
	GOM	PAC	GOM	PAC	GOM	PAC	GOM	PAC	GOM	PAC	GOM	PAC	GOM	PAC
Flow Underground	1	0	1	0	0	0	0	0	0	0	0	0	1	0
Flow Surface	3	0	3	0	2	0	1	0	2	0	4	0	4	0
Diverter Flow	0	0	1	0	0	0	0	0	0	0	0	0	1	0
Surface Equipment Failure	3	0	3	0	4	0	3	0	1	0	0	0	1	0
LOSS OF WELL CONTROL (TOTALS)	7	0	8	0	6	0	4	0	3	0	4	0	7	0
COMBINED TOTAL FOR THE YEAR	7		8		6		4		3		4		7	
SOURCE: BSEE Database as of 16-Aug-2013														

Figure 5.2 Loss of well control during the years 2007 to 2013 in the GOM and PAC /30/

5.2.3 The Hydrocarbon Releases (HCR) Database System

The HCR database contains information on offshore releases of hydrocarbons in the UK. For each leak there is information available covering which system that is leaking and some information about root cause etc. Some systems involve both topside and subsea facilities and it can therefore be difficult to know if the leak has occurred topside or subsea. Manifolds are one of these systems that involve both topside and subsea facilities. The available information for manifolds doesn’t give any explanation whether the leakage is subsea or topside and can therefore not be used to find information about incidents on subsea facilities only. Some information can nevertheless be extracted for subsea wellheads and subsea XTs. Figure 5.3 shows the leaks divided by cause of accident.

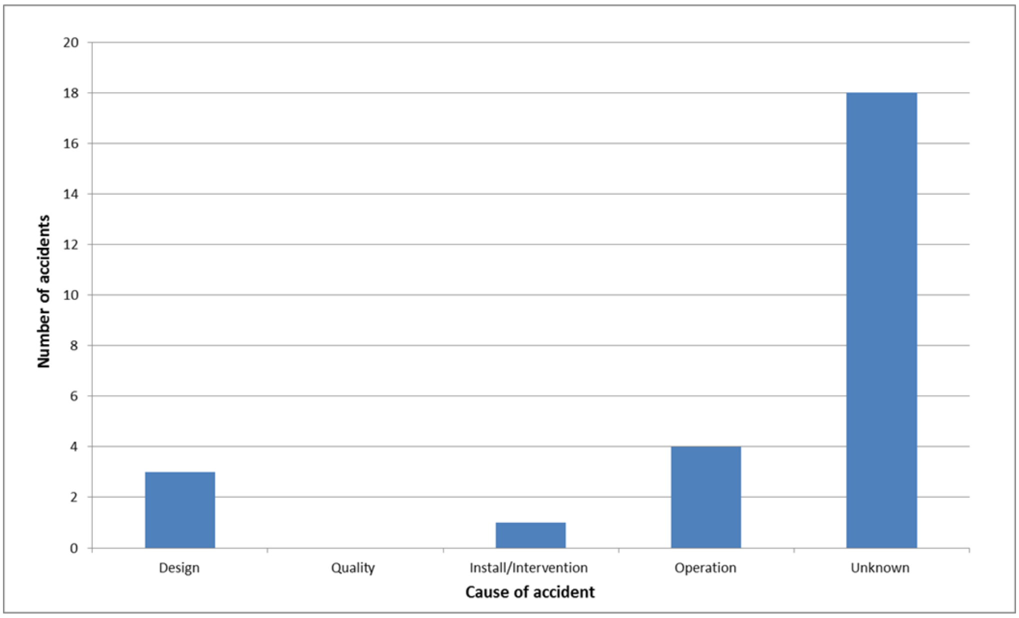


Figure 5.3 Leaks in UK on subsea wellheads and subsea XTs divided by cause of accident /1/

The root cause for the leaks is here classified by accidents related to design shortcomings, quality issues, leaks during installation / intervention, leaks due to abnormal operation and unknown cause. The categories are described in the same way as for "Hendelsesdatabasen", see section 5.2.1. The HCR database is structured slightly different compare to the "Hendelsesdatabasen" and uses the abbreviating codes; 'design cause', 'equipment cause' and 'operational cause' instead of a description of the accident. The information in these categories, in the database, is used to classify the leaks to the cause of accident according to Figure 5.3. The cause of accident due to design is for leaks where the abbreviating code in the HCR database is "YES" for the category design cause. Leaks because of quality issues exist when equipment cause is due to manufacturing or material defects. The operational causation, in the HCR database, is sorted under following subcategories incorrectly fitted, improper maintenance, improper inspection, improper testing, improper operation, dropped object, opened up whilst containing hydrocarbons, none etc. If the operational causation is one of the mentioned subcategories, excluding none, then the cause of accident is operation according to Figure 5.3. The result from cause of accident in UK and NCS is similar, compare Figure 5.3 and Figure 5.1. Most of the accidents are classified as due to unknown cause and the same conclusion can be drawn about that the available information is not sufficient as have been made for NCS, see section 5.2.1.

Comparing Figure 5.1 and Figure 5.3, it can be seen that the amount of leaks that is possible to link to subsea facilities in UK is much less than for NCS. A reason for this is the limited data that can be sorted out for subsea. There are leaks where it isn't possible to know if the leak is subsea or topside as mentioned above. It may therefore be more leaks from subsea facilities than is shown in Figure 5.3.

5.2.4 Other Regions

The national petroleum safety authorities representing other regions such as Australia, Asia and Brazil are collecting information on accidents and uncontrolled release of hydrocarbons or other leakages from subsea production installations. These data has not been made available.

5.2.5 Most serious incidents

NCS:

- In 2013 a bleed valve was set in the open position by a mistake, the estimated oil spill was 2.5 tonnes. /28/
- In 2003 the largest uncontrolled oil spill from a NCS subsea installation happened when 500 - 800 m^3 of oil leaked out due to rupture in connection between manifold and production line to platform. /51/
- From July 2002 until January 2003 approx. 30 m^3 was released due to wrong operation of a valve on the manifold. /28/

There are also a significant number of leakages of control fluids reported in the "Hendelsesdatabasen"

- In 2012 approx. 16.5 m^3 control fluid more than planned was released over a period of 14 days. Normal release is 4.2 m^3 in 14 days. /28/

UK:

- 1993 there was a leakage from a wellhead in the UK sector where approx. 13.5 m^3 of oil leaked out. The cause was mechanical failure during shut down of the well. /1/
- In 1996 a XT was leaking and approx. 41.6 tonnes of gas leaked out. The operational causation in the HCR Database is "Dropped object". /1/
- In 1996 a leak was discovered during final commissioning of a subsea manifold. The root cause was identified as hydrogen embrittlement (HISC). /50/

6 INTEGRITY MANAGEMENT

6.1 System integrity

System integrity is defined as both the containment of fluids, and the reliable operation of safety- and production-equipment (valves, etc.). The objective is to ensure the safety and function of the installation.

System integrity is established during the concept, design, fabrication, installation and pre-commissioning phases (project phase) and maintained in the operations phase.

6.2 Subsea Integrity Management (SIM)

SIM can be defined as:

> *The management of a subsea production system to ensure that it delivers according to the design requirements and national regulations, and does not harm life, health or the environment, throughout the required field life.*

This implies that the operator needs to establish, implement and maintain a management system that ensures the integrity of the system throughout its service life /25/, /32/.

6.3 Life Cycle Information (LCI)

Life cycle information: Information required by Company for engineering, mechanical completion, commissioning, preparation for operations, start-up, operation, maintenance, repair, modification and decommissioning of a plant. LCI includes what has previously been termed Documentation for Operations (DFO) /52/.

6.4 Barriers

The integrity of subsea production systems is of significance to society and the environment. Several measures are necessary to maintain acceptable risk exposure:

- Measures to reduce possibility of failures or accidents occurring
- Measures which limits the damage caused by such events

Many people apply the terms preventive and reactive barriers to such measures, often illustrated by so called bow-tie diagrams as shown in Figure 6.1. In a wider perspective, these barriers embrace technical, human and organisational elements working together /52/, /54/.

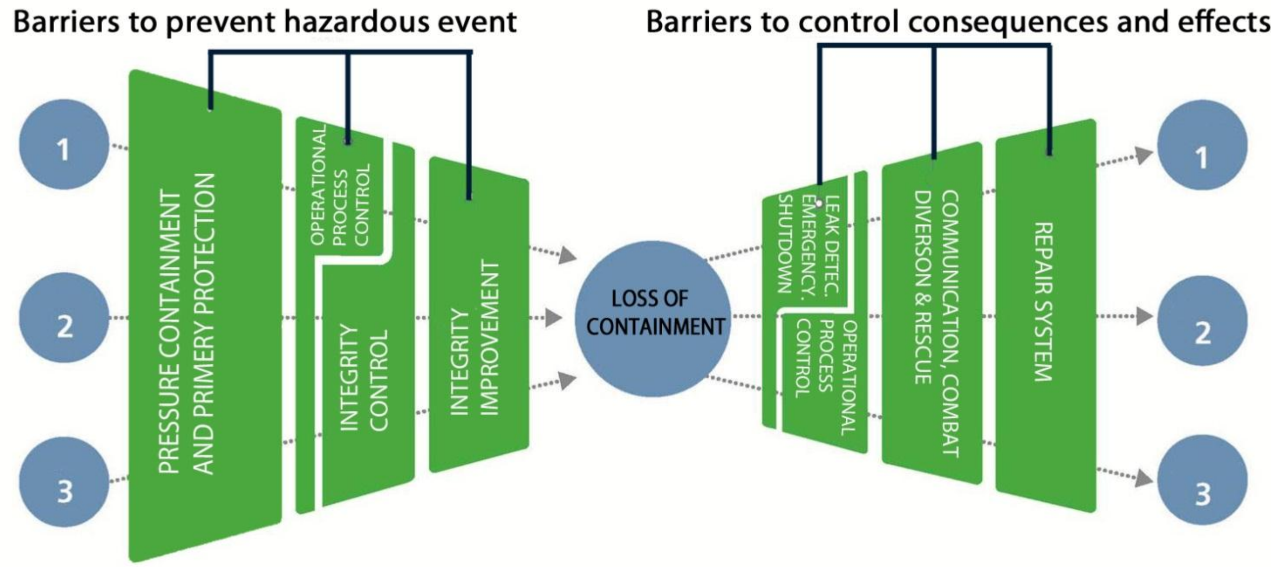


Figure 6.1 Bow-tie diagram

Barriers are any kind of measures put in place to prevent a hazardous event (preventive barriers) and any measure that breaks the chain of events to prevent or minimize consequence escalation should the hazardous event take place (reactive barriers). Such measures can be physical or non-physical (human/operational/organisational). Preventive barriers are illustrated on the left side of the bow-tie, whereas the reactive barriers are illustrated on the right side of the bow-tie. A top event can be loss of containment or loss of functionality of a valve. Possible causes for a top event can be described by threats to the system.

6.5 Threats

A threat can be defined as an indication of an impending danger or harm to the system, which may have an adverse influence on the integrity of the system /25/.

A threat is not only related to the degradation of materials or physical damage to a system but can also be incidents associated with design, operation or organisational matters.

Identification of threats should be carried out early during a project development and be supported by all relevant engineering disciplines (e.g. resources with background from both design and operation, with in-depth knowledge of the system in question). The identified threats need to be taken into consideration both in the project phase (design) and in the operations phase.

Background information that should be used in the identification of threats is:

- Previous risk assessments, HAZID etc. (carried out both during the project and operation phase, as relevant)
- Design documentation
- Inspection reports
- Operator's and industry experience, e.g. failure statistics.

Each threat may lead to a failure, undesirable situation or an abnormal condition. The possible consequences of such an occurrence can be described in terms of failure modes. Some failure modes (abnormality) may be due to a specific degradation mechanism, whilst others are event based.

Each identified threat should be assessed with respect to the confidence in the background information and, if relevant, the inherent robustness of the design. Threat identification is commonly carried out for threats causing loss of containment but threats associated with functionality and the organisation responsible for the integrity of the system should also be identified. Threats can therefore be split in two main areas:

- Threats causing structural failures and loss of containment
- Functionality threats

A proposal for threats to be considered within each threat group for subsea facilities and umbilicals are given below:

- Design, Fabrication and Installation (DFI)
- Material degradation
- Internal medium
- Third party
- Structural
- Control system
- Natural hazard
- Operational
- Organisational

Table A-1 in Appendix A summarises threats and associated failure modes that generally can be associated with a subsea facility and umbilical. Other threats than the ones listed here may also be relevant dependent on the actual equipment and the application in question. It can sometimes be convenient to prepare a list of threats for the main components (e.g. manifold, XT, umbilical elements) within a system. A description of the different failure modes are given in Table A-2 in Appendix A.

It should be noted that a primary damage can develop into a secondary damage. E.g. a third party damage may cause a degradation of the coating which may subsequently lead to external corrosion (i.e. metal loss).

The likelihood for a threat to occur may vary over the service life of a SPS. New threats may become relevant based on new knowledge or the design criteria for controlling a threat may have changed. The latter is most relevant for a life extension of a system.

Threats are not only related to the physical and technical condition but can also be associated with organisational matters. Integrity control is also a matter of controlling all organisational aspects related to design and operation of a system. Organisational threats are relevant for the whole life cycle (from design to operation and abandonment) of a system. This typically includes administration, people, procedures, reporting, documentation etc. Table A-3 in Appendix A summarises typical organisational threats to consider.

6.6 Safety philosophy

The safety philosophy established in design should generally apply. However, the original safety philosophy may be modified as a result of the operator’s change of practice running and controlling the system, technology development and improved knowledge of the systems.

Safe operation means that a subsea facility and an umbilical is operated according to a set of acceptance criteria established in design and revised throughout their service life based on new knowledge of the system.

Revisions of the acceptance criteria can take place as a result of:

- Improved knowledge regarding known threats to the system
- Identification of new threats
- Re-qualification of the system (e.g. change in basis of design)
- Changes in authority regulations or company requirements

6.7 Integrity management system (IMS)

Integrity management is not only a matter of operational control on a daily basis. Integrity management should start already during the early design phase, since choices made at that stage may have impact on the operation of the system.

In a lifecycle perspective (Figure 6.2) there are three important stages related to the Integrity Management Process:

- **Establish integrity** during the concept, design, fabrication, installation and pre-commissioning phases (project phase)
- **Transfer integrity** from the project phase to the operations phase
- **Maintain integrity** during the operations phase (commissioning, operation, de-commissioning, re-commissioning, re-qualification and lifetime extension) and abandonment phase

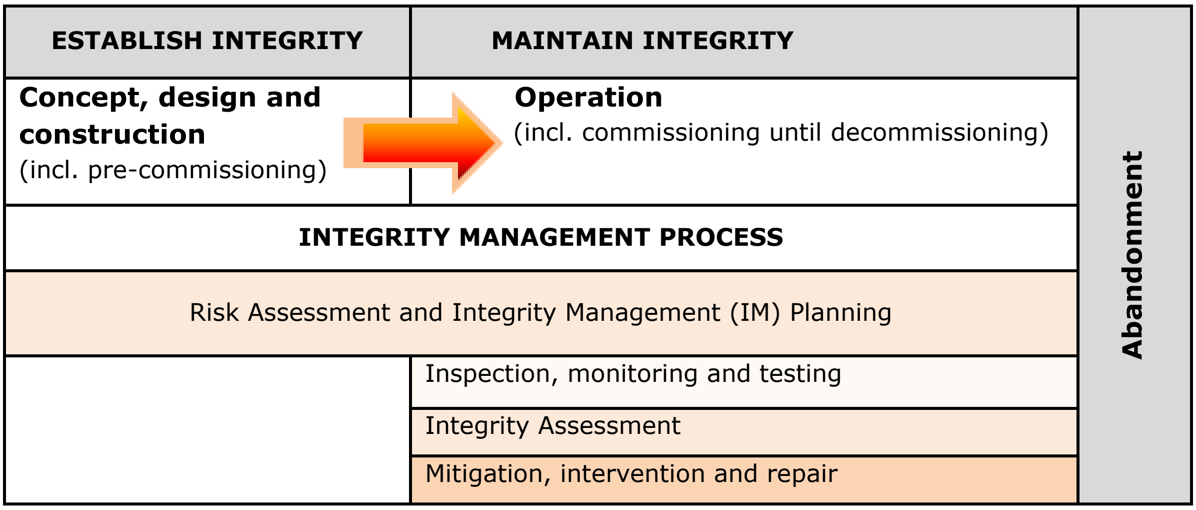


Figure 6.2 Integrity management in a lifecycle perspective

Establish integrity is related to the concept, design, fabrication and installation phases. Choices made in the design, like selection of the type of equipment, materials, monitoring systems, new or proven technology, robustness of design, redundancy, and fabrication and installation methods, will be decisive for the integrity of the system. This includes identification of the main threats to the system and their associated risks, and subsequently developing strategies to manage these risks during the operation phase.

Transfer of integrity from design to operation involves transfer of relevant data required for the safe operation of the subsea production system.

Maintaining integrity covers the operation phase including any prospective life extension or requalification of the system.

6.7.1 Integrity management process

An integrity management system consists typically of elements, as shown in Figure 6.3. The Integrity Management Process (inner wheel) is the core of the Integrity Management System. The elements; company policy, organisation and personnel, reporting and communication etc. are elements that support the integrity management process.

Integrity Management is a continuous and iterative process that should be part of the whole lifecycle of the system, including the project development phase where the integrity is established, the operations phase and the abandonment phase, as illustrated in Figure 6.2.

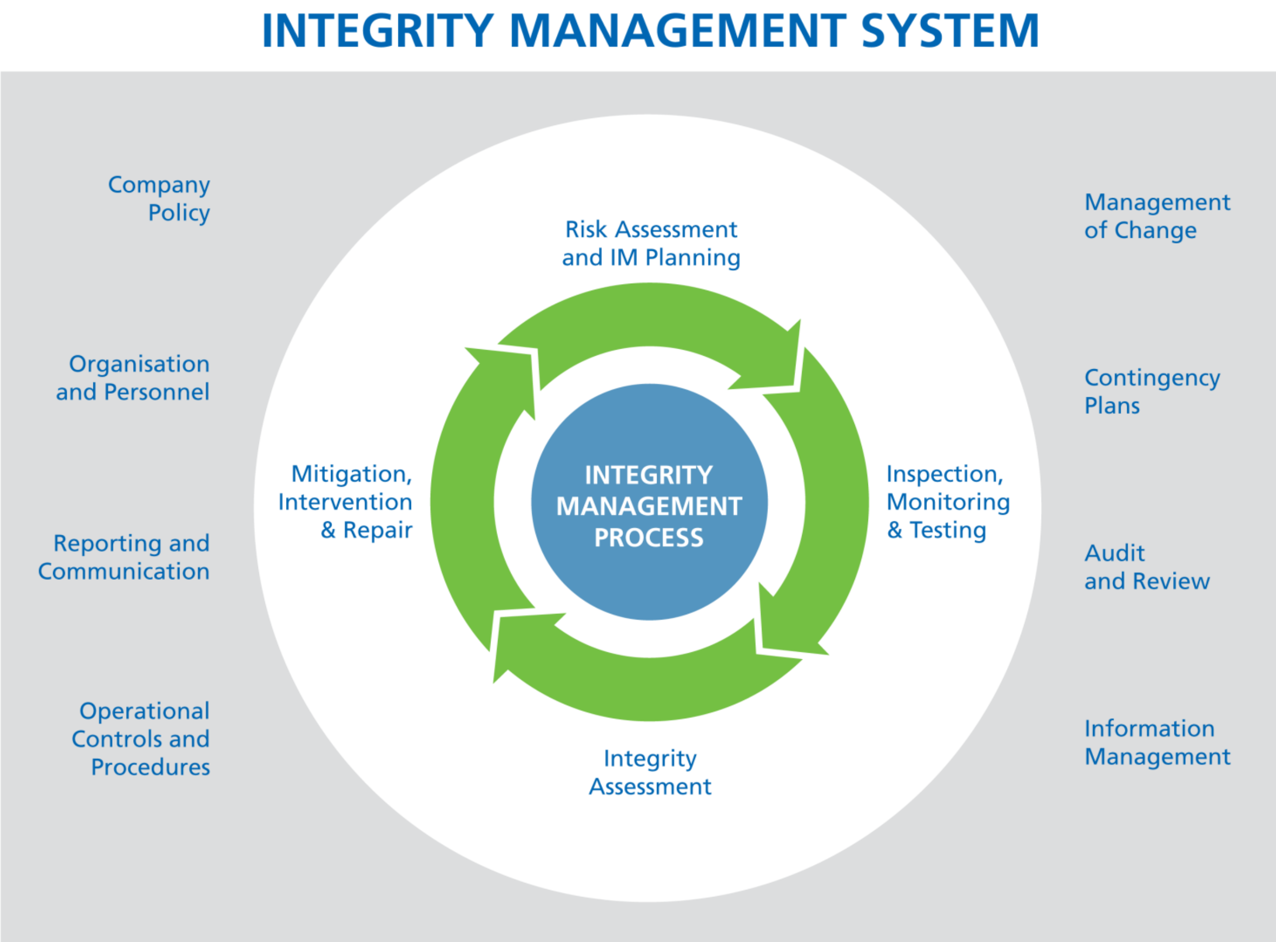


Figure 6.3 Illustration of an integrity management system. The integrity management process is the core of the IMS /25/.

The Integrity Management Process commonly consists of four main activities /25/, /32/:

- Risk Assessment and Planning, which includes threat identification, risk assessment, long term and short term (annual) planning for inspection, monitoring and testing
- Planning and execution of Inspection, Monitoring and Testing activities

- Integrity Assessment based on inspection, monitoring and testing results and other relevant life cycle information (See definition in e.g./26/)
- Planning and execution of required Mitigation, Intervention and Repair activities

The risk assessment and integrity management planning shall be based on historical data for the system gathered during inspection, testing and monitoring. The data from such activities should be properly documented to ensure traceability on the operational history of the facility, traceability of data and to enable trending. The risk assessment working process is illustrated in Figure 6.4 and gives an example on different activities needed for an integrity assessment. The integrity assessment may be split into;

- Corrosion assessment covering internal and external corrosion
- Mechanical assessment covering e.g. fatigue, displacement, settlement, well growth, third part damage

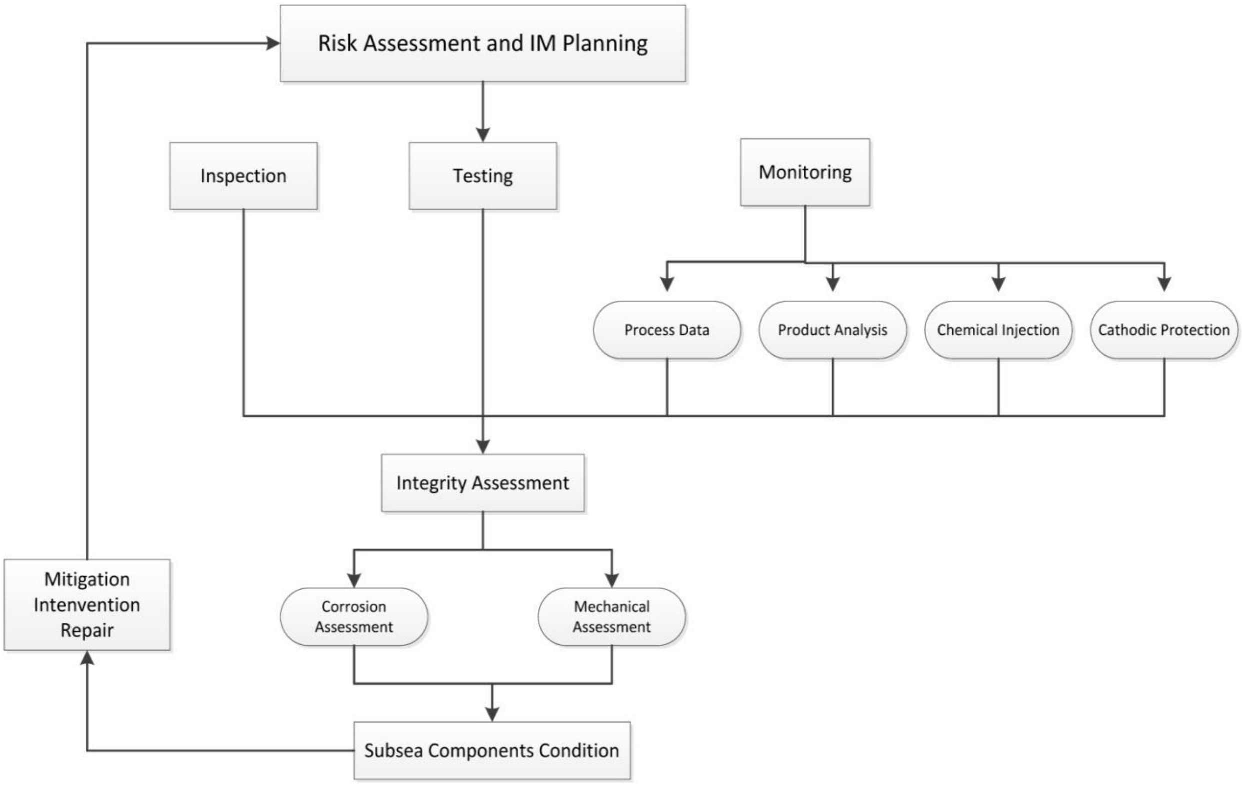


Figure 6.4 Risk assessment working process

6.8 Guidelines and standards for establishing a SIM system

There exist few guidelines or international standards for integrity management of subsea production systems. There are, however, documents available related to pipeline integrity management system (PIM) that can be used as basis when establishing an integrity management system, irrespective of type of equipment. The overall integrity management system will still have the same main elements.

Table 6.1 below shows some of the currently available and upcoming guidelines and standards for establishing and maintaining an integrity management system.

Table 6.1 Standards and guidelines for establishing an integrity management system

Standard and guideline references		
❖ **DNV [1] Recommended Practices**		
DNV-RP	DNV Recommended Practice F-116 for integrity management of submarine pipeline systems, 2009. New revison planned launched Q1 2014	2011
DNV-RP	DNV GL Recommended Practice 0002 for integrity management of subsea production systems planned launched Q1 2014	2009 - (ongoing JIP for extension of RP)
DNV-RP	DNV Recommended Practice-F206 Riser Integrity Management	
❖ **International Standards**		
ASME B31.8S	Managing System Integrity of Gas Pipelines	
ISO 13628	Petroleum and natural gas industries - Design and operation of subsea production systems	
API Std 1160	Managing System Integrity for Hazardous Liquid Pipelines	
AS/NZS 4804	Occupational health and safety management systems – General guidelines on principles, systems and supporting techniques	2001
AS 2885.3	Pipelines - Gas and liquid petroleum-operation and maintenance	
NORSOK Y-002	Development of national standard for lifetime extension for transportation systems on behalf of OLF – leading to the NORSOK Y-002 standard	2010-2011
NORSOK U-009	Development of national standard for lifetime extension for subsea systems on behalf of OLF – leading to the NORSOK U-009 standard	2010 -2011
NORSOK U-001	Subsea production systems	
API RP 17N	Subsea Production System reliability and Technical Risk management	
API RP 17A	Design and Operation of Subsea Production Systems-General Requirements and Recommendations,	2010
PAS 55	Asset Management To be published as ISO 55000 in January 2014	2008
❖ **Other references**		
Energy Institute	DNV UK participated with input and guidance to the 'Guidelines for the management of integrity for Subsea facilities'	2009
CEPA [2]	Facilities Integrity Management Program Recommended Practice, 1st Edition	2013

1) Publications not yet harmonized with company name DNV GL

2) Canadian energy pipeline association /20/

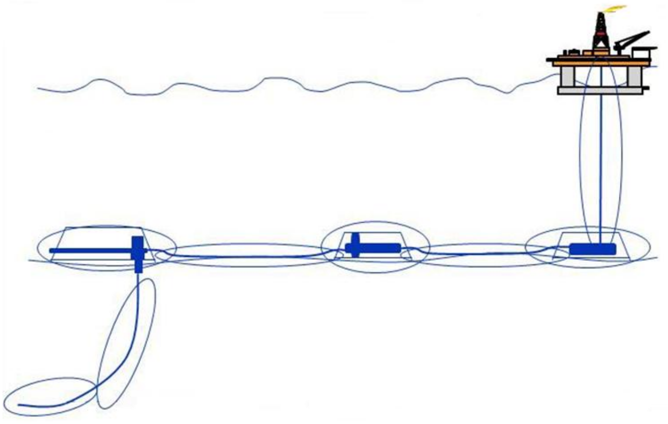
6.9 Main challenges related to Integrity Management in operation

Experience has shown that information management and documentation is a challenge to operation of a subsea facility. Moreover, organisational interfaces can also be a threat for sound communication and exchange of operational data across operator's organisation. This can typically be associated with:

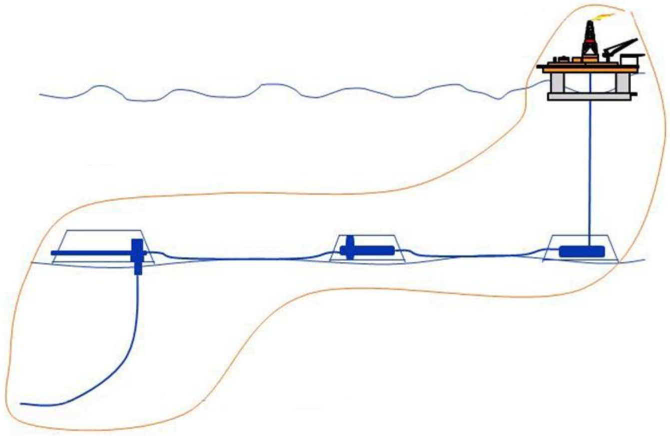
- Organisational interfaces can be a challenge for managing the integrity management process, see Figure 6.5
- Difficult to retrieve documentation from DFI phase
- Difficult to find maintenance and replacement history
- Lack of operational history during service life (e.g. fluid composition, temperatures, pressure, sand and water contents, abnormal operations, etc.). Table 6.2 gives an example of data retrieved in connection with a life extension project /41/. The table shows that it is challenging to retrieve data across the operational organisation
- Difficult to establish the condition of process equipment due to the bullet points above
- Limited learning from retrieved equipment. This equipment should be used to establish the current condition and predict the remaining service life for the same or similar equipment elsewhere in the subsea production system

Table 6.2 Example of retrieved data for a life extension project /41/.

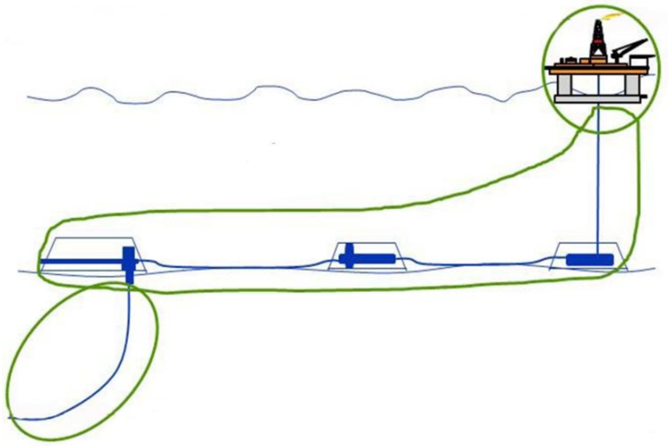
<table>
<tr><th>Year</th><th>Wellhead Temperature</th><th>Wellhead Pressure</th><th>H_2S content</th><th>Sand content</th><th>Oil, Water, Gas content
Well testing</th></tr>
<tr><td>Year n-1</td><td rowspan="7">No data</td><td rowspan="15">No data</td><td rowspan="15">No data</td><td rowspan="15">No data</td><td rowspan="3">No data</td></tr>
<tr><td>Year n-2</td></tr>
<tr><td>Year n-3</td></tr>
<tr><td>Year n-4</td><td rowspan="10">Data available</td></tr>
<tr><td>Year n-5</td></tr>
<tr><td>Year n-6</td></tr>
<tr><td>Year n-7</td></tr>
<tr><td>Year n-8</td><td rowspan="4">(Year n-7) to (Year n-11)
$T < T_{design}$</td></tr>
<tr><td>Year n-9</td></tr>
<tr><td>Year n-10</td></tr>
<tr><td>Year n-11</td></tr>
<tr><td>Year n-12</td><td rowspan="4">No data</td></tr>
<tr><td>Year n-13</td></tr>
<tr><td>Year n-14</td><td rowspan="2">No data</td></tr>
<tr><td>Year n-X</td></tr>
</table>



Contractors scope of work:
Several EPC contactors are usually involved in a project, as illustrated by the blue circles



Operators responsibility:
Operator is responsible for the overall system as illustrated by the red circle



Typical Operators organisation:
Within the operator organisation there can be different organizational responsibilities:

- Drilling and well
- Underwater (pipeline, riser, SPS)
- Platform

This is illustrated by the green circles

Figure 6.5 The figures illustrate organisational interfaces during EPCI, operator responsibility and a typical way of organising the operation organisation.

7 DEGRADATION MECHANISMS AND FAILURE MODES

7.1 Description of Failure modes

A failure mode can be defined as a condition where the equipment for some reason is no longer able to perform its intended purpose. A failure mode can be e.g. leak, loss of function, clogging, metal loss, cracking etc. Table A-2 in Appendix A gives an overview of typical failure modes with a description of the failure modes and possible causes.

The different threats described in Table A-1 in Appendix A may lead to different types of failure modes. For instance corrosion may lead to leak, burst, cracking, metal loss and loss of function. When assessing different threats to an equipment or system, the associated potential failure modes need also to be assessed individually.

The consequences of the different failure modes may vary. Some can be handled by e.g. a change in the operation of the system, whilst others may be catastrophic.

The failure modes that can be associated with material degradation will depend on the degradation mechanism that occurs. Material degradation is not only related to corrosion or erosion but can also be degradation of material properties due to exposure to e.g. chemicals, elevated or low temperatures etc.

7.2 Degradation mechanism

The threat 'material degradation' may be due to several degradation mechanisms which is dependent on the exposed environment and the material in question. Degradation mechanisms can be divided into two main groups:

- Time dependent degradation mechanisms
- Abrupt degradation mechanism

Time dependent mechanisms are to some extent possible to trend by inspection and their development may be possible to predict. However, this is not the case with abrupt mechanism. Controlling abrupt mechanism will require other means of surveillance, such as e.g. monitoring critical parameters or these mechanisms must be handled during design (e.g. materials selection).

Examples of abrupt degradation mechanisms are:

- Environmental cracking due to the presence of H_2S and chloride
(Design: ISO-15156 /8/; Operation: Process control and monitoring)
- Hydrogen Induced Stress Cracking
(Design: DNV F-112 /18/; Operation: Avoid overload)
- Brittle fracture of ceramics

Examples of time dependent degradation mechanism are:

- CO_2-corrosion of low alloy steel
- Ageing of elastomers and thermoplastics
- Loss of spring capacity (e.g. for accumulators)
- Fatigue

An extended list of examples on time dependent degradation mechanisms and available models for predicting the degradation are given in Table 7.1. Additional information on degradation mechanisms and ageing of material can be found in /40/ and /42/.

Table 7.1 Examples of time dependent degradation mechanisms.

Degradation mechanism	**Prediction models available**	**General Comment** **Note: CS – Carbon / Low alloy steel** **CRA – Corrosion resistant alloys**
CO_2 corrosion	/5/, /6/, /7/	CS: Models available. Flow induced shear forces can enhance the corrosion by removing protective corrosion films accelerating the corrosion. CFD can be used to determine area with high wall shear stress locally. Causes metal loss. CRA: Considered fully resistant to CO_2 corrosion. Wall shear stresses not relevant.
Microbiological Influenced Corrosion	-	MIC is most often associated with CS and is considered less likely on CRA. An assessment of the risk for MIC is required on a case by case basis. Causes metal loss.
O_2 corrosion	/12/, /13/	CS: Models available. High flow can aggravate the corrosion (flow enhanced corrosion). For injection water upsets in oxygen control can cause severe corrosion over time. Corrosion of umbilical armour. Causes metal loss. CRA: Needs to be handled through material selection. Guidance given by design codes. 3)
Corrosion due to organic acids	-	CS: Needs to be assessed on a case by case basis. Causes metal loss. CRA: Corrosion not expected at levels existing in a production environment.
H_2S general corrosion	-	CS: Models not commercially available. Causes metal loss. CRA: Needs to be assessed on a case by case basis.
Corrosion due to elemental sulphur/sulphur containing compounds	-	Models not available, needs to be assessed on a case by case basis. Causes metal loss.

Degradation mechanism	**Prediction models available**	**General Comment** **Note: CS – Carbon / Low alloy steel** **CRA – Corrosion resistant alloys**
Galvanic corrosion	-	Models not available. Galvanic corrosion is not desirable and needs to be handled through design.
Corrosion caused by chemicals	-	Exposure to chemicals used for well intervention and clean-up needs to be assessed on a case by case basis.
Erosion (from sand and e.g. particles from well cleaning)	/14/	DNV RP-O501 /14/ and Computational Fluid Dynamic (CFD) erosion simulations. Causes metal loss.
Coating degradation/ Cathodic disbonding	/11/	No models are available for coating degradation but CP design codes give a prediction for thin film marine coating and thick film corrosion coatings.[2)] See photo in Figure 7.**1**.
Chemical degradation of elastomers and thermoplastics	/15/	The polymer properties are affected by exposure conditions (production fluid, chemicals, temperature and pressure). Prediction model is preferably based on the Arrhenius equation, NORSOK M-710 /15/.
Physical degradation of elastomers and thermoplastics	-	Physical degradation of polymers may be wear, extrusion, creep, rapid gas decompression (RGD) damage, fatigue or electrical breakdown of isolators. NORSOK M-710 /15/ covers RGD.
Fatigue	Guidance given in ISO 13628-5 (Umbilical) & ISO 13628-7 (Workover riser) /21/, /22/	Assessment of fatigue resistance may be based on either S-N data obtained from representative components or a fracture mechanics fatigue-life assessment. Wellhead fatigue and XT fatigue capacity may be established by using ISO 13628-7.
Wear (abrasive wear)	-	No models available. Needs to be handled through material selection
Consumption of galvanic anodes [1)]	/9/, /10/	Recommendation given in CP design codes. See illustration in Figure 7.**2**.

1) Consumption of anodes is strictly not a degradation model as galvanic anodes are installed with the purpose of being consumed over the design life of the system. However, for system subjected to life extension, the

degree of anode consumption becomes an important part when assessing the system feasibility for life extension.

2) It is currently a requirement that coating for subsea applications is qualified for cathodic disbonding.

3) Oxygen pollution may be introduced into production systems through e.g. chemical injection, that may have impact on the corrosion rate.

4) Soft seals are a general term for seals made of elastomers or thermoplastics.

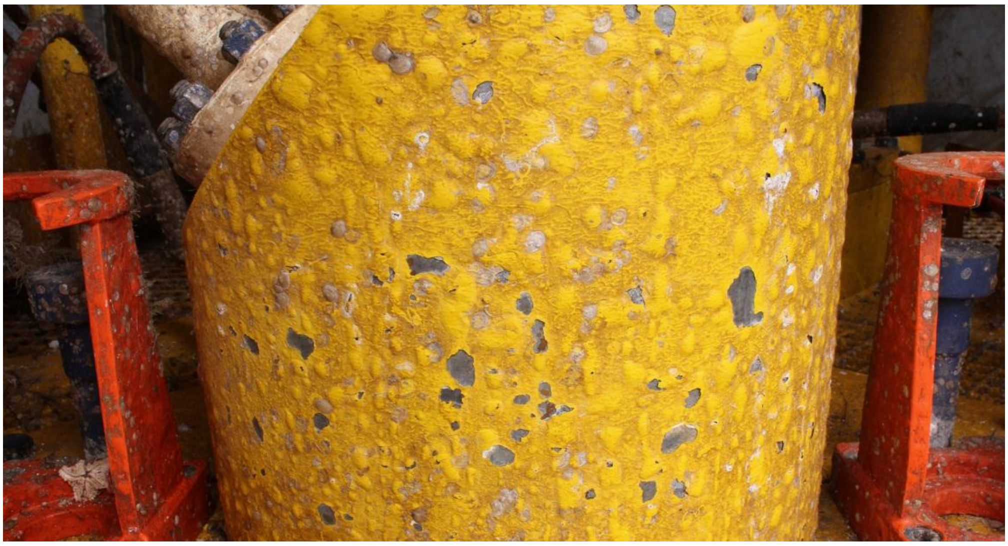


Figure 7.1 Example of coating breakdown after approx. 15 years in service.

Figure 7.2 Example on totally consumed galvanic anode

7.2.1 Metallic materials

Corrosion prediction models are primarily used as a tool during the design phase for determining the corrosion allowance of low alloy steels. Use of low alloy steel will normally require some means of corrosion control in the production system (use of corrosion inhibitor, oxygen control) in addition to monitoring of the efficiency of the corrosion control system. Compared with a pipeline, the efficiency of a corrosion inhibitor for a subsea XT and manifold is questionable due to the complex flow patterns. Moreover, they are not possible to inspect by internal inspection tools. Degradation mechanisms causing wall thinning will reduce the pressure containment capacity of the system and may lead to external leak or burst. Materials selection is therefore based on use of CRA in order to avoid any metal loss /46/, /47/.

Implementation of a sand control strategy and use of CRA will strongly reduce the risk of metal loss and increase the system robustness.

Relevant standards that give guidance for materials selection and material requirements for:

- SPS are: ISO 13628-1/3 /3/, NORSOK M-001 /2/, ISO-15156 /8/, ISO 21457 /4/
- Wellhead and tree equipment are: ISO 13628-4 /3/, NORSOK M-001 /2/
- Umbilicals are: ISO 13628-4 /3/, NORSOK M-001 /2/

A recommended practice for a design to obtain resistance to HISC of duplex stainless steels is given in DNV-RP-F112 /18/. A Recommended practice for design under erosive conditions is given in DNV-RP-O501 /14/. Relevant time dependent degradation mechanisms to be considered can be found in Table 7.1.

Degradation due to exposure to e.g. sulphur containing compounds and chemicals will need special assessment on a case by case basis.

External corrosion is normally not a major concern, since all subsea equipment is provided with cathodic protection. It is, however, important that electrical continuity checks are carried out prior to installation and that the design of the CP system is adequate for the service life of the system.

7.2.2 Elastomers and thermoplastics

Elastomers and thermoplastics are used in electrical insulation, packer elements, umbilical sheaths, coating, as seal material, etc.

Soft seals in subsea equipment are vital to the function of the equipment and to avoid unintentional leaks to the environment. Yet the seals are usually given lower consideration compared to other elements of the design; they are often inexpensive, they are not considered as primary barriers to the environment and there is often a lack of competence by designers on polymer materials. However, soft seals are used both as primary barriers and secondary barriers. For instance soft seals are used as primary barriers on actuator stems and failure may cause minor leakages to the environment.

Important properties to consider for a soft seal are:

- Mechanical properties
- Temperature resistance
- Resistance to chemical exposure
- Resistance to rapid gas decompression

Seals are exposed to a number of chemicals (e.g. the production fluids and gases, drilling fluids, inhibitors, well stimulation fluids and mixtures thereof) that may affect the material by swelling, extraction or chemical reaction and deterioration.

As a consequence, materials which inherently are minimally affected by a range of chemicals have been used for subsea applications. Such elastomers are among the types HNBR's, FFKM's, some FKM's and FEPM's. Thermoplastic sealing materials often chosen are for instance PTFE or PEEK. Although all these are chemical resistant polymers, they still may be affected and fail by exposure to some oilfield chemicals. Thus it is important to apply experience and knowledge in selecting an appropriate seal material.

Seals wetted by other fluids than production fluids, such as electrical insulation/sealing materials and sealing materials for hydraulic systems are typically exposed to a better controlled environment. The major concern in such services is often the additive packages of chemicals that may attack the sealing materials.

Subsea thermal insulation is typically based on elastomers, thermoplastics or thermoset. Degradation mechanisms for thermal insulation may be;

- Water ingress and reduced thermal properties
- Thermal ageing and possibly cracking of the insulation
- Cathodic disbonding

Thermal insulation systems for subsea facilities are normally based on rubber type of insulation and are normally qualified for 25 years' service life. This includes service condition of 95°C and with a surrounding seawater temperature of 4°C. For systems operating at lower temperature, the thermal ageing will be 'slowed down' and the performance of the coating may last for a longer service life (Arrhenius equation, NORSOK M-710 /15/). See illustration in Figure 7.3.

Table 7.2 summarizes the main degradation mechanisms relevant to elastomers and thermoplastics in subsea applications.

Figure 7.3 Use of rubber coating on piping

Table 7.2 Degradation mechanisms for elastomers and thermoplastics in subsea applications.

Degradation mechanism	General Comments
Creep / Compression sets	Creep is an increase in deformation with time at constant pressure. Compression set is if the part of deformation is still present after realising the pressure.
Volume swell	Absorption of fluids over time that may result in volume increase and deformation and weakening of the elastomer if unconstrained or induce stress if constrained (e.g. seal).
Seal shrinkage	Seal shrinkage can be caused by extraction of plasticisers and additives by contacting fluids or chemical reactions and post curing. Furthermore, loss of possible plasticisers will change the mechanical properties, e.g. the low temperature properties of the elastomer may be deteriorated.
Thermal expansion & contraction	Caused by changes in the temperature that may lead to over-compression failure or leakage due to difference in thermal expansion coefficient between the seal or gasket and the housing.
Compression fracture	The present ultimate strength properties of the elastomer are exceeded often due to unforeseen pressure peaks or movements in the housing for dynamical applications.
Chemical degradation	Chemical degradation is chemical changes in the polymer matrix due to a chemical reaction with the polymer's surroundings. Resultant changes in

Degradation mechanism	General Comments
	mechanical properties may affect functional performance. NORSOK M-710 describes the requirements to qualify soft seals to subsea service. Included are simulated production fluids for qualifying sealing materials to sweet or sour service conditions. M-710 does also prescribe that testing against bespoke fluids should be performed.
Thermal Ageing	Polymer deterioration as a result of overheating. Thermal degradation generally involves changes to the molecular weight of the polymer and typical property changes include reduced ductility and embrittlement, chalking, cracking, and a general reduction of physical properties.
Extrusion damage	At elevated pressure the seal can sometimes be extruded into the gland's diametric clearance gap.
Wear/abrasion and fatigue	Loss of material over time by rubbing against another surface for dynamic seals.
Housing effects	Faulty design, installation damage or dynamic movement in housing, e.g. excessive pump shaft movements.
Rapid gas decompression	Rapid gas decompression (RGD) damage may occur when high pressure is released and the fluid that has permeated into the sealing material under high pressure does not permeate out of the material, but expands within the material thus causing material failure. Rapid gas decompression is also called explosive decompression. This kind of failure is probable with elastomer seals, but rare with thermoplastic seals. This is due to the larger free volume and lower modulus of elastomers. Thus there are no requirements to RGD-resistance for thermoplastic seals in NORSOK M-710. NORSOK M-710 describes the requirements to qualify elastomers for RGD resistance under standard conditions.
Weathering (umbilical)	Photo-induced degradation and chain scissoring leading to colour changes, reduced tensile strength and impact resistance. Exposure to ozone and other atmospheric contaminants can accelerate the process.
Micro-organisms	Bio-degradation due to bacteria, fungi, yeasts and their enzymes.
Electrical	Degradation and treeing of polymer material due to electrical breakdown. Dielectric failure is a common failure for insulator materials. Contamination, thermal ageing, repetitive excessive voltage stress, and mechanical deformation speed up dielectric breakdown.
Manufacturing, storage and handling	Degradation could also be a result of; • Incorrect materials selection • Fault during production of the polymer material • Inadequate design • Inadequate specification • Incorrect installation • Incorrect preventative maintenance • Operation outside design limits • Careless handling

A description of the function and failure modes for elastomer and thermoplastic seals can be found in /15/. A review of elastomer applications for the offshore industry, with focus on seals, can be found in /16/.

8 CURRENT KNOWLEDGE AND FUTURE RISK

8.1 Material degradation

Historically, there have been relatively few incidents that have caused serious discharge of production fluid from SPS. Most serious incidents have been in connection with drilling and well operation. The PSA's CODAM database covering reported discharged to sea in the North Sea from subsea facilities from year 1997 to 2013 /38/, has shown that the majority of the discharges are hydraulic fluids and MEG. Some hydrocarbon leakages has however been observed from valves, couples and in connection with retrieval of equipment and during well operation. Only a couple of small leaks at umbilical terminations have been reported. No leaks have been reported due to external corrosion.

Generally, inspection, and retrieval, of equipment has shown that the external corrosion protection system (coating in combination with cathodic protection with galvanic anodes) has been efficient and that coating breakdown factors used for CP design have been conservative. Some incidents of external corrosion have occurred but this has mainly been related to lack of electrical continuity and not CP system failure. Lack of CP capacity has been experienced in some instances where current drain to equipment has not been accounted for in design or where a combination of small and large anodes has resulted in early depletion of the smaller anodes.

Prospective degradation mechanisms of materials in a production environment are generally well established but not all mechanisms are well understood or are predictable. Since internals of umbilicals and SPS are almost not possible to inspect or repair in field, common practice for corrosion control for permanently installed equipment has been, and still is, selection of materials resistant to the exposed environment in order to ensure a robust and maintenance free design. Low alloy steels have therefore seldom been used for process wetted parts. This has resulted in a standardisation of material grades used for subsea facilities compiled in standards and recommended practices /2/, /3/, /4/. However, this does not mean that the degradation of the material has not happened but publicly available failure data does not conclude on root cause for the observed failures (due to operational condition, manufacturing, improper materials selection etc.) Apparently, this knowledge remains mainly as in-house knowledge within the operator's organisation, maybe because this is considered as sensitive information. Some serious incidents have, however, been regarded as of common interest to the industry, and has resulted in a JIP to establish e.g. new design requirements.

Example on this are:

- DNV RP F-112 /18/
- JIP - Steel forgings for subsea application initiated December 2013

Fasteners: It has historically been too low attention to the quality of fasteners than with other types of metallic products. The importance of material traceability and acceptance test of batches of fasteners for subsea applications has not been sufficient, and has resulted in several failures. There is currently an increasing awareness in the industry regarding fasteners. As part of this awareness, a JIP was established in 2008 with the aim of providing a technology basis and present best industry practice for the design, specification, procurement and installation of externally threaded fasteners /23/.The guideline gives guidance for developing fastener specifications, assembly procedures and design criteria in accordance with industry best practice.

Soft seals: Soft seals have traditionally been given low attention and have been considered as consumables and been replaced during e.g. XT refurbishment. Soft seal often constitute a second barrier for external leak for permanently installed equipment like valves. NORSOK M-710 first issued in 1994 aimed to give requirements for qualifying soft seal for subsea service. It is and has been a challenge for the industry that only the minimum requirement given in M-710 has been subjected for qualification, overlooking any additional tests or requirements that M-710 recommends. The actual application or service conditions are often not considered, especially the vast range of chemicals used, and "M-710 qualified" is stated as proof that the sealing material can be used in any subsea application. It must be stressed that NORSOK M-710 does not give the full picture of seal qualification requirements as only material service life and rapid gas decompression resistance is evaluated. It appears that new projects are utilizing the same sealing technology as for previous project, without looking into how they actually have behaved in service. A JIP ("Performance assessment of soft seals") has recently been launched aiming to develop test methods for procedures and routines to learn from seals in service by using pulled equipment refurbishments and operator's log data as opportunities for gathering information from seals in actual service.

8.2 Future subsea facilities

As the installation of SPS tends to:

- ✓ Go deeper
- ✓ Have reservoirs with higher temperature and pressure
- ✓ Be in fields located in regions with a colder climates (artic)
- ✓ Include installation of subsea processing equipment (demand for more power)
- ✓ Be at a longer distance from infrastructure

Hence, other threats than described in Table A-1 in Appendix A may become relevant. Moreover, degradation mechanisms that have not been of importance for more benign conditions may become important to consider. The ambient temperature at the seabed in artic regions may not change much from fields further south but temperature during storage of equipment before installation will need to be taken into consideration (exposure to low temperatures and icing).

Fields with higher temperatures will inevitably increase the application temperature range. This is a challenge for elastomer and thermoplastic seals due to the thermal coefficient of expansion for a polymer being about ten times that of steel. Thus, the polymer seals will have difficulties sealing in the lower temperatures and at the upper temperatures. This may increase the risk of seal extrusion or over-compression damages. New developments with design requirements exceeding temperature Class U ISO 10423 /53/, seems to end up with a high number of soft seals qualifications.

Higher temperature/pressure and prospective more corrosive production fluid may also call for other CRA grades than used today. Developing new material grades for a harsher environment may be required.

Development of fields in the arctic region may also call for more knowledge of the behaviour of such materials under extreme temperature conditions.

There is also a trend of installing more and more instrumentation for condition monitoring to also monitor the condition to the SPS. A challenge is to understand what to look for, how to monitor, and how to configure and trend the data (see Sect. 10 for further details). Currently there is limited experience with interpretation and trending of such data.

There is an increasing use of Safety Instrumented Systems (SIS) subsea. The uses of such SIS can allow designers to reduce the safety factors in the mechanical design and compensate through the use of a SIS.

There is a risk that SIS may fail to provide the level of safety required. Therefore companies require a statement that the SIS conforms to its requirements, normally called a SAR. There is no requirement for this SAR to be produced by an independent third party and the quality of the SAR can vary considerably. Furthermore, traditional component verification activities are not sufficient to ensure the quality of these SIS and firmer external regulatory controls and verification appears to be required.

Manifolds has for the last years become more complicated design wise. Due to requirements for easy retrieval of manifold without affecting the trees, horizontal connections between tree and manifold are being preferred. This requires certain flexibility in branch pipe do accept required displacement within acceptance criteria for displacement stresses. In addition flexibility to accept well growth also has to be accounted for. This result in very flexible branch pipe designs which now are seeing different load scenarios compared to previous manifold design. This results in new failure modes which is vibration due to seawater current velocities as well as internal flow induced vibration. This also results in a more complex manifold design which will be more packed, making them more difficult to inspect /44/.

It appears as a general trend that the former 'safety margins' related to materials are reduced. Alloying elements in duplex stainless steels (e.g. 22Cr. 25Cr) are at the 'lower range' and the production methodology are changing affecting the properties of the materials (e.g. precipitation of nitrides). This may reduce the material robustness by altering the corrosion resistance of the material, its resistance to HISC and it may reduce weldability /47/.

For certain application (HP/HT), there may be a need for heavier forgings than formerly used. There is a risk that use of heavier forgings will give a less robust design, since it will be more challenging to control the properties of the material. Other solution may need to be developed in the future for such instances /47/.

8.3 Standardised building block subsea development

In order to cut project lead time there are an upside in using standardised building block subsea development. For some prospects the time from sanction to first oil / gas is crucial for the business case. To succeed with required delivery time it is important that the chosen technology is mature and proven and not requires engineering for qualification or performance validation work. This is the idea with the 'Fast Track projects'. However, there is a concern amongst engineers in the industry that those projects are having other set of challenges which may result in:

- Less time for improving the design of the equipment, resulting in replication of a former design that was considered as only 'good enough'
- Limited availability of preferred materials within the required timeframe (a material grade specified for the SPS may be replaced with an alternative material with unknown track record)
- Less time and focus on manufacturing/fabrication follow-up. Follow-up is costly
- Risk for missing out purchasing of spare parts and specific long lead items in due time (e.g. bolts, forgings)
- Less acceptance for engineering support to supply/sourcing management

Contractors commonly use long term frame agreement with agencies supplying raw material from different sub-suppliers. This may reduce traceability of the materials and restrict access to preferred materials. Selection of credible and fewer sub suppliers which are familiar with the purchaser requirements (e.g. NORSOK requirements) are considered as important in order to obtain a robust design. High activity resulting use of inexperienced personnel may cause failures due to lack of adequate experience. Deliveries are also price driven which may force suppliers to place order in low cost countries having less experience with stringent requirements to material grades.

Learning from retrieved equipment and equipment taken out of service can make a good basis for assessing similar systems and to establish a better understanding of materials degradation as recommended by PSA (Activity Regulations § 50).

The design calculation tools become more and more accurate, which allows a reduction in design factors. This again can make the equipment less robust against calculation errors, fabrication faults, damages related to installation or operation.

8.4 Existing subsea facilities and life extension

The safety level established in design shall apply for a system that is operating within the time frame of the service life. The set of acceptance criteria that were established in design may, however, change based on operational experience and new knowledge. New threats which were not encountered for in design may also have become relevant. Prospective material degradation (wall thinning) may also require re-assessment of acceptance criteria. These factors are especially important when considering life extension of a production system.

Examples on potential future threats for a SPS and umbilical considering life extension are:

- Increased H_2S content in production fluid due to well souring – materials not resistance to environmental cracking
- Increased water cut – increased temperature that may exceed design temperature
- Increased amount of produced water - increased risk for scaling and need for higher volumes of scale inhibitor
- There is an increasing probability for sand production at late field life, which increases the risk for erosion
- Lower flow rates – accumulation of sand in manifold piping
- Damaged sand screens – increases risk for erosion
- Uncertainties related to ageing of soft seals. Lack of qualification records of seal materials or limited documentation of sealing material grade, resistance to chemicals, RGD and temperature
- Replacement of chemicals (with unknown additives) and its impact on soft seals and potentially valve trim materials. Composition of oilfield chemicals changes due to new HSE requirements
- Reduced capacity of the cathodic protection system
- Permeability of polymeric materials
- New knowledge regarding environmental conditions (e.g. sea current) – affecting fatigue life

- Unable to operate equipment like valves due to e.g. wear, erosion, loss of spring capacity, accumulator failure etc.. with the consequence of loss of barrier function or less functionality
- Design and qualification of components has been based on a design life of 20-25 years (e.g. bend restrictor, soft seal). Fitness for life extension becomes uncertain since relevant data are not available
- Control system failures - Loss of electrical or hydraulic power
- Increased insulation resistance in power cables due to e.g. internal leaks in umbilicals
- Changes in third party damages as trawling, anchoring, dropped objects loads and frequency which may will require more robust means of protection

Any impact of operational deviation and mitigating action needs to be considered when assessing a system for a life extension.

Life extension of the cathodic protection system can, however, be obtained by installation of anode banks or retrofitting of anodes where feasible.

Experience from life extension projects has revealed lack of quality to life cycle information (LCI) of components. This applies both to design documentation and operational information such as:

- Process data (e.g. temperature and pressure data)
- Inspections (extensive use of negative reporting)
- Repairs (difficult to retrieve information easily, sometime used other sources for information)
- Interventions (intervention carried out that may have impact on other parts of the system)
- Design data

Manufacturing documentation is commonly stored with suppliers for ten years as part of contract. After that, the contractor has no responsibility in keeping this information. Experience from life extension project is that only limited DFI information is available within the operator’s organisation. This information is of high importance in order to assess systems feasibility for life extension. Lack of vital information will reduce the system knowledge and confidence in that the system are fit for an extended service life. A possible scenario may be that system or components are being scrapped due to lack of documentation.

There appears to be an improvement potential for how vital information of the systems is stored. There has recently been launched a JIP with the aim of standardizing required documentation to be produced, maintained and managed for a subsea development project /24/. Lack of consistency and rationality between different operator and suppliers documents can affect quality, be time consuming and be a cost riser.

Due to lack of in service experience with some types of soft seals, as discussed in Sec. 8.1, it is a challenge to have any basis for assessing life extension of such materials.

9 MONITORING, INSPECTION AND TESTING METHODOLOGY

The purpose of monitoring, inspection and testing is to detect existing or developing faults and to validate the integrity or function of barriers and equipment. All the monitoring, inspection and testing activities generate a large volume of data that needs to be analysed in order to determine if the integrity of the system is jeopardized and what potential actions should be performed. Figure 9.1 illustrates the process.

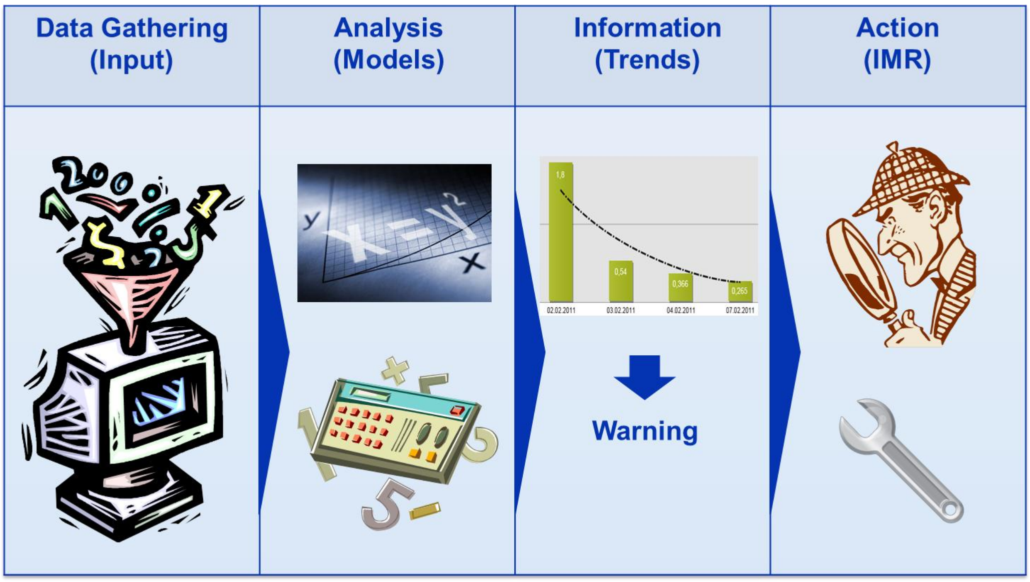


Figure 9.1 Monitoring, Inspection and Testing process

- **Data gathering** – Data is collected from sensors, inspections and integrity tests of the system. The data is then stored in a database or repository
- **Analysis** – The data is analysed to determine for example a reduction in capacity or performance, for example loss of anode mass
- **Information** – The result of the analysis is compared to earlier results to determine a trend. If possible the remaining life should be estimated. If the result exceeds a given threshold then an assessment of the situation and risk should be initiated
- **Action** – If deemed necessary then an appropriate action should be initiated. This could include increased surveillance, immediate or planned maintenance or replacement

Due to the large volume of data generated from instruments, inspections and testing the analysis and trending should to a large extent be performed autonomously by the surveillance system and warn the operator when predefined thresholds are exceeded.

Some challenges with such systems include:

- **What to record** – The data needs to be stored in a consistent manner and with consistent units that will enables analysis of the phenomena of interest
- **Noise reduction** – removal of spurious data points which can disturb or distort analysis of the data
- **Time scales and data reduction** – some data is recorded on a millisecond basis while other may be on a yearly basis. Data reduction must be performed for the data to be useful

- **Transients** – Transients during start-up or abnormal operations may cause the monitoring system to trigger an alarm or may result in the need to do a lot for data filtering

9.1 Monitoring methods

Monitoring generally means to be aware of the state of a system. Monitoring in this context can generally be spilt in to two main categories:

- **Process monitoring** – is the monitoring of the production process with the goal of assuring or optimizing the flow of the hydrocarbons. This can include pressures, temperatures, flow rates, fluid composition, etc.
- **Condition and Performance Monitoring (CPM)** – the process of determining the condition of machinery while in operation. This is often done by monitoring a parameter (temperature, vibration, efficiency, etc.) in order to identify a significant change which is indicative of a developing fault

A large portion of the instrumentation subsea is for process monitoring although many instruments can serve a dual purpose. The instruments include pressure and temperature sensors, multi-phase flow meters, sand detectors, pig detectors, salinity probes, water detectors, etc. These sensors may again feed data into flow assurance software that analyses the process parameters and assists the operator in optimizing the production. Generally, the key to a successful condition monitoring program includes: knowing what to monitor, how to interpret the data and when to put this knowledge in use.

Condition monitoring can generally be split into two categories:

1. **Safety and Environmental** – Monitors the integrity of the pressure containing barriers. The goal is to detect either a degradation or loss of a barrier and in turn take action to avoid or minimize leaks to the environment. Examples include well annulus monitoring to verify the integrity of the production tubing, leak detection system to monitor the XT and manifold or sand detectors to help manage erosion and maintain the containment integrity.

   Monitoring activities may cover the items below:

   - Leak detection – Acoustic, capacitance, mass balance etc.
   - Sand detectors against erosion
   - Well annulus monitoring for production tubing integrity
   - Pressure sensor with pressure protection systems
   - Vibration sensors against fatigue
   - Fluid composition (e.g. content of CO_2, H_2S, water, etc.) to estimate corrosion rates
   - Sea current measurements to determine level of vortex induced vibration on riser and remaining fatigue life

2. **Performance and Availability** – Monitors the health and performance of subsea equipment. The goal is to identify equipment that is getting close to failing and plan corrective actions such that impact on production availability is minimized. Examples include monitoring of functions / components within the SCM, vibration levels on rotating equipment, valve actuator signatures.

Monitoring activities may cover the items below:

- Hydraulic and electrical signatures for valves
- Internal resistance in power cables and umbilical
- Vibration of rotating machinery for lifetime prediction of bearings
- Temperature and vibration levels for electronics and motors
- Hydraulic fluid consumption and fluid levels
- Cv estimation for chokes
- Pump efficiency
- Efficiency of power systems by monitoring electrical current, voltage and power
- Validation of sensors through redundant sensors and flow assurance systems

9.1.1 Challenges and Experience

Traditional production control systems were monitoring processes with relatively slow process dynamics. Condition and performance monitoring systems may in many cases be monitoring systems with much faster dynamics. This may require improved instruments and data sampling systems. The amount of data being transmitted from a subsea installation may also increase considerably. There is a risk that the introduction of new equipment and an increase in data will introduce faults into the control system. It will be important to ensure adequate independence between critical functions (control functions and safety functions) and monitoring functions, so that the reliability of the critical functions is not compromised.

9.2 Inspection methods

The main activities associated with the inspection are Planning, Execution, Assessment of inspection results and Reporting and documentation, as summarised in Table 9.1.

Table 9.1 Main activities associated with inspection

Main Activity	Examples of Sub-activities
Planning	The **planning** for an inspection includes the following: - Detailed description of the purpose of the inspection and the scope of work - Specification of reporting format - Development of work packages - Preparation of work instructions and procedures - Establishment of responsibilities and communication lines between inspection Contractor and Operator. procurement of equipment - Establishment of plans for the mobilisation of equipment and personnel - Carrying out risk management activities for the inspection activity
Execution	The **execution** of the inspection includes the following: - Mobilisation of personnel and equipment and transportation to the site - Carrying out safety activities - Completing the inspection activities - De-mobilisation - Preliminary reporting towards the specified reporting criteria
Assessment of inspection results	The **assessment** of inspection results includes the following: - Quality control of the inspection results - Leak rates - Estimate remaining anode mass - Marine fouling - Amount of subsidence - Level of deformation due to impact - Status of valves - Visibility of subsea marking
Reporting and documentation	**Reporting** of the inspection and final reporting of the inspection includes: - Findings are usually documented by photos, movies or 3D photo - Listing of inaccessible areas - Issuing of final inspection report

Today, the primary method of inspection of subsea systems is through the use of ROVs. General Visual Inspection (GVI) is performed through the use of the ROV's cameras. GVI is an important method but it is limited to what the inspector / operator can see through ROV cameras and also restricted by ROV access within the template structure. The main objective is to look for major damages and leaks. GVI is generally performed once a year and a standard inspection program will typically include:

- Protection structures: Check for impact damages, anodes, coating, marking, scouring, mud mat, foreign debris, subsidence.
- Manifolds: Damages, leakages, vibrations, anodes, coating

- XT: Damages, vibrations, leakages, valve status, connections, anodes, coating
- Pipelines: Leaks, impact damage, free spans, upheaval buckling, wall loss due to corrosion/erosion by intelligent pigs, anodes, coating

Inspection techniques may include:

- General visual inspection with or without cleaning
- Close visual inspection with cleaning
- CP recordings (Protective potential)
- Remaining anode mass
- Sampling of gas to reveal its origin
- Leak rate measurements
- Wall thickness measurements possible – may need special equipment
- Vibrations measurements

Inspection activities may include:

- Crack detection and sizing
- Corrosion/erosion – internal: Wall thickness measurement
- Corrosion – external: Visual inspection for evidence of corrosion, wall thickness measurement
- Coating damage: Visual inspection
- Marine growth: Visual inspection, thickness measurements
- Leaks: Visual inspection for detection of leaks to the environment
- Deformation: Visual inspection
- Damage: Visual inspection for permanent deformations
- Subsidence: Visual inspection or relative height measurements
- Scouring: Visual inspection
- CP-system condition: Visual inspection for assessment of anode depletion and check for damage to anode fastening cables, measurement of protective potential (see Appendix 3 for details)
- Foreign object detection

9.2.1 Experience and Challenges

Leak detection – Gas leaks can quite easily be detected whilst water soluble liquids like methanol and hydraulics are more difficult. Leaks from the SPS are rear but most often leaks are due to natural release of shallow gas. Analysis of the gas can reveal its origin. Older wells where the reservoirs pressures have dropped typically have a lower operating pressure. For such wells leaks are less more common to observe. Also since the internal pressure then can be lower than the external pressure the leaks would result in water ingress in to the system.

Experience transfer – Challenges and findings during inspections that could improve the design of the next generation SPS are typically not reported back to those carrying out design.

Accessibility – It is easier to inspect satellites than manifolds. It is a trend that SPS sizes are made smaller and becomes more compact and with the protection structure the ROV access is reduced.

Cleaning needs – Marine growth is a challenge for equipment located on shallow water (e.g. 40-80 m) whilst fine soil is the main challenge for deeper fields where fin particles are whirled up by the ROV reducing visibility.

Drawings – It can sometimes be challenging to receive relevant drawings of the equipment prior to planning the inspections. Clarification meetings with the operator are often required in order to get all the relevant information.

Reporting – Reporting of inspection results should aim at being in a standardised format to ease the assessment work, fulfil reliability and maintenance reporting requirements for CMMIS (Computerized Maintenance-Management Information System) purposes (see ISO 14224) and to better allow for trending of inspection data such as corrosion rates, valve function, etc.

Work practice - All work instructions, procedures, communication lines and responsibilities, which are mandatory for a safe and cost-effective inspection process, and which constitutes the operation manual, should be implemented as part of the subsea integrity management system(SIMS).

9.3 Testing methods

Many functions or components of a subsea production system are regularly tested in order to verify its function or its integrity. One example is testing of well barrier elements (down hole safety valve and production isolation valves)/54/. Barrier testing of a valve is defined as testing the integrity of a valve to perform as a barrier, i.e. ability to isolate upstream and downstream. Most tests are monitored using installed sensors but there can be tests that are performed by ROV tools or monitored by the ROV cameras. There are many different types of testing and some of them include:

- Valve barrier testing
- Pressure testing – internal
- Pressure testing – external
- Function (e.g. valves, actuators, etc.)
- Continuity / communication (cables, tubing, fibres)
- Insulation resistance
- Electrical system test
- Instrument testing and calibration
- General communication

In order to perform integrity- or function-tests effectively, the tests should be planned for in the design phase. Generally there will be a need for some instrumentation in order to determine if the test is successful. Also, there needs to be a method to evaluate the data and determine if results meet predefined acceptance criteria.

10 FUTURE TRENDS, DEVELOPMENTS AND CHALLENGES

10.1 Future trends

Future trends and future technology will be based on several scenarios. Today oil-companies are focusing on reducing cost. This may lead to less interest in developing new advanced technology, but at the same time this must be seen in an overall perspective for the prospective fields. If an advanced subsea solutions with e.g. some processing capacities will increase the overall recovery or reduce cost for investment or operation of a platform, the criteria for investment of new subsea technology is in place.

OG21 published a report in 2012, TTA 4 "Future technologies for production, processing and transportation" /43/ which aims at giving recommendation to the Ministry of Petroleum and Energy regarding what prioritized area for research and development in order to close the technology gaps that can contribute to realizing the full business potential on the NCS (see Figure 4-1). Governmental funding though Petromaks and Demo 2000 shall also prioritize funding according to conclusions in this report. Figure 10.2 is showing the structure of the OG21 report.

Figure 10.1 The relationship between government, OG21, research council, Petromaks and Demo 2000 /43/

In order to identify future technology needs three business cases were established.

- ✓ Business case 1: Barents sea gas condensate field development
- ✓ Business case 2: Oil and gas developments in environmentally sensitive areas
- ✓ Business case 3: Field life extension

The technology needed for those three business cases varies. In a meeting between the document authors, it was discussed whether the new large discovery at the Edvard Grieg field would change the conclusions in the report. It was discussed and agreed upon that the technologies identified were very robust even with this new discovery in mind.

The identified technology gaps and competence areas were then also split in two categories;

- governmental funding is required
- the industry itself develops the needed technology or competencies

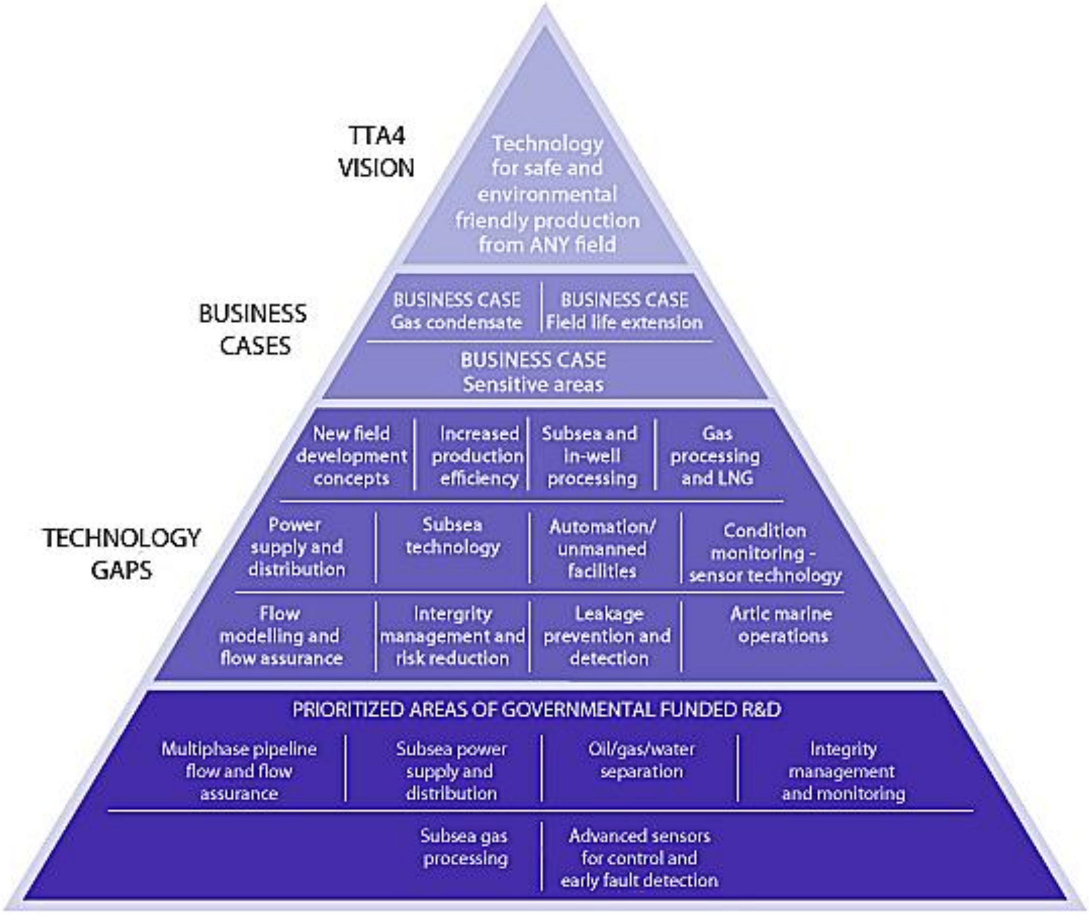


Figure 10.2 Structure of the OG21 TTA4 report "Future technologies for production, processing and transportation"/43/

Looking forward there will be two main focus areas:

1. **Standardised building block design field developments**

   For fields with limited or uncertain resources, cost is an overall factor as well as time to get return on the investment. Speed for development and construction is a key for the investment. The goal is quick deliveries without sacrificing quality or safety.

2. **The advanced subsea system where new and novel technology will be developed**

   The industry advances into more hostile environment and need to go for the more difficult hydrocarbons. This challenges calls for new technologies to be developed.

Those two focus areas can be visualised today with Statoil, where they at the same time executes their fast track project portfolio as they are developing Åsgard and Gullfaks subsea compression. Also an interesting reflection here is that these ground breaking technologies are being developed in mature fields and not necessarily together with new green field developments.

In a global perspective it is focus area 1) 'Standardised building blocks' that will contribute most to volume in investments and number of units installed. In other words, standardising the subsea industry will most likely lay the foundation for its own business by being more attractive compared to platform based developments also with respect to HSE.

As described in OG21 TTA4 /43/ and the referred business cases, those areas which will be released for oil and gas activities will drive the need for competence and technology differently.

Developments in for example the Barents Sea will have requirements based on remote location and currently there is little infra-structure with emphasis on how to transport the production fluids. Long well stream transport distances and new flow regime may call for research to cope with new parameters for transport of unprocessed well fluids. A scenario in Lofoten, Vesterålen and Senja may call for same challenges as for Barents Sea but here the activities will be closer to shore and thereby there may be additional environmental requirements to operate in those areas.

Currently there is an understanding that the industry needs to address quality costs and also to pursue standardisation. Quality costs must be seen in two different scenarios:

- Quality costs are paramount for manufactures in order to deliver on time without financial overruns.
- Quality for operators means reliable systems that give required uptime as well as maintenance and repair cost at a reasonable level. Here the biggest financially risk may be loss of production.

10.2 Standardisation

Today 'standardisation' is a buzzword in the industry, illustrated by Figure 4-3. However, the word 'standardisation' in this context has not been defined. It is important to address that standardisation is not just about materials, specifications, components and interfaces; it is also how the projects are delivered and handed over to client or operating organisations. It is important to address standardisation in such a way that innovation is not restricted. Overall aim with standardisation is to remove work that does not contribute to either quality or functionality. One example today is the lack of a common standard for supply of materials. The effect of this is that the supply chain are hesitant to order materials for own risk and cost prior to have a contract with the customer in place. Typically this adds 7 – 12 months of lead time for forgings.

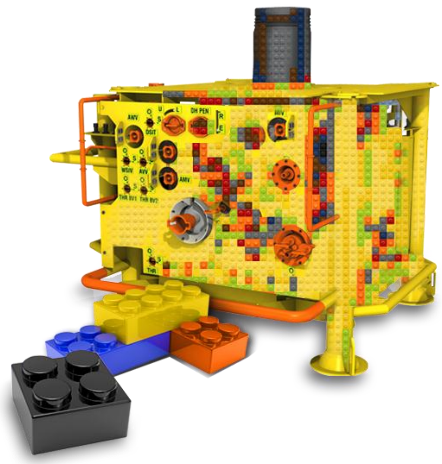


Figure 10.3 Standard subsea building blocks (Image: Aker Solutions)

The importance of addressing standardisation during project execution is visualised by the launch of a Joint Industry Project (JIP) with the aim of standardising subsea documentation. This is work that is supported by the members of Norsk Olje og Gas (Norwegian Oil and Gas Association) /48/.

Today the oil and gas industries are facing several challenges. One of the challenges is delivery capacity, and thereby also delivery time. Other is increasing costs. In Norway the Norwegian Oil and Gas Association has made a report with the title "A report on Norwegian Subsea Standardisation" /48/ which summarises a number of initiatives that has been initiated in order to make the industry more efficient. Similarly, the Society of Petroleum Engineers (SPE) is working with similar goals, however with different approach and different means.

10.3 Developments

The new developments that are ongoing with respect to subsea process will push the limits of the complexity of what has being installed on the seabed so far. For condition monitoring this will create another challenge compared to what the industry has today. It is likely that knowledge and experience gained from condition monitoring of these complex systems will over time migrate into conventional subsea system.

When it comes to subsea processing it is difficult to predict what the trend will be since any business case being explored will have their unique circumstance and therefore individual needs. It is however believed that for compressor stations, it will be smaller units compared to what we see at Åsgard. They will be more compact, more cost effective and flexible to install. An effect of this is probably a solution with lower energy efficiency.

Subsea electrical power is areas were the industry is investing heavily in order to qualify technology that is more compact, more reliable and more cost effective. Large companies that are well known industry players for high voltage high power systems are contributing to these developments often with the financial backing of the major oil companies. An overall driver here is the need for high power subsea consumer's, particularly driven by subsea compression. Key for development here is the high number of components that will be installed on the seabed which has never been on the seabed before. This has the potential to reduce the reliability of these systems if not properly qualified. Crucial components like Variable Speed Drives (VSD), switch gear and voltage transformations will be located on the seabed. The distance from power producer or distance to nearest host platform for power regulation will be driving factor for what to develop and in what sequence. A subsea compression solution for Ormen Lange will require more electrical components and systems to be installed on the seabed compared to Åsgard or Gulllfaks due to the difference in step-out distance for the electrical power transmission. However, the maximum step-out distance is constantly being increased through new techniques and technologies. The next generation of subsea power systems will therefor most likely be more compact, more reliable and cost efficient.

It should also be mentioned that the equipment developed for the subsea oil and gas industry are to some extent same type of components that is needed for electrical transmission from offshore wind-farms.

11 RECOMMENDATIONS FOR IMPROVEMENT OF KNOWLEDGE SHARING

It appears that knowledge sharing, across competing companies and buyers and sellers, is not so easy and that there are many obstacles hindering this recommendation of sharing. There exists and will be commercial reasons for why players in the industry will not make incidents available to public. In this context there may be a dispute between equipment vendor and buyer, or it can be an ongoing arbitration between insurers and the party setting up the claim. Information related to design solutions will also be a reason for why some may not want to disclose detailed information. Information that can harm a party's reputation will also be a reason for why it is hard to get the data available to others.

In the preparation of this report several databases and public sources have been examined. They have been sources for information for accidents, incidents and uncontrolled spill of fluids. It is however a challenge to extract information that can be used for trending or establishing the root cause for an incident from these open sources. In some cases it is difficult or impossible to understand if the incident or uncontrolled leakage is related to subsea- or topside facilities. However, it would be of great benefit for the industry to have the data as comprehensive as possible to allow trending and establishing root causes. From PSA it is defined in the ”Styringsforskriften” what information that shall be reported and what form(s) to fill in. However all the necessary information is not always provided and then it might end up not being reported.

The examination of other countries databases or sources shows that the available data is harder to extract here. In addition, there are no uniform structures, so comparing different regions is not possible with required confidence in the data.

The subsea industry is today an international industry where the technology and techniques used are universal. The applied technology is based on the same design codes and the service contractors and equipment vendors' are delivering all over the world. A majority of the upstream oil and gas producers also operate internationally. It is the view of DNV GL that it would benefit the industry as well as the authorities to have larger source of data to trend, in order to make precautions gained from experience.

It is recommended and considered of outmost usefulness and of importance, with respect to HSE and equipment development, that the industry takes further responsibility for knowledge sharing. Furthermore the information provided should be more transparent through international databases where useful information can be retrieved.

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APPENDIX A
Threats to Subsea Facilities and Umbilicals

Table A-1 Threats, threat description and associated failure modes. Text in cursive is only relevant for umbilical (U).

Threat group	Threat - Examples	Threat description – Examples	Failure mode
DFI Threats	Design	• Lack of understanding of relevant design standards • Details of interfaces not ready during design • Lack of experience/ Newcomer in the market • Lack of knowledge • *Stretching of technology, different interpretation of qualified design (U)* • Improper/Unfortunate design • Unfamiliar with project specific design requirements • Basis of deign incomplete, inconsistent or subjected to late changes • Incorrect materials selection • *Inability to capture effect of bitumen on armour stress (U)* • Design shortcoming • *Incomplete 3rd party verification (not able to pick-up failure or shortcomings in design due to splitting of verification scope between various suppliers(U)* • Lack of analysis tools	Burst Metal loss Leak Cracking Yielding Collapse Loss of function Material ageing
	Manufacturing	• Newcomer in the market • New materials with unknown performance for the application in question • Lack of resources for manufacturing follow-up • Construction yards with lack of experience with relevant authority regulation and project specific specifications and standards • Challenges implementing project specific regulations and requirements • Smaller deliveries – less focus from fabrication yard • Culture awareness • Lack of qualification of manufacturer • Lack of traceability of raw materials • Use of inexperienced personnel due to high activity • Shortcoming and damage during manufacturing	
	Fabrication	• Newcomer in the market, inexperienced personnel • Lack of resources for fabrication follow-up • Fabrication yards with lack of experience with authority regulations and standards for design • Welding shortcoming • Damage or shortcoming during assembly (e.g. Bolt torque or physical	

Threat group	Threat - Examples	Threat description – Examples	Failure mode
		damage) • Lack of or insufficient FAT	
	Coating application	• Newcomer in the market • Lack of resources for follow-up during coating application • Lack of knowledge • Coating shortcoming • *Perforation of umbilical plastic outer sheat causing damage to internals (U)*	
	Testing	• Failure during pressure testing, system integration testing, control system testing • *Incorrect tensioner grip force for umbilical(U)* • Risk of not capturing relevant failure modes during testing	Leak Burst Cracking Yielding Collapse Loss of function
	Temporary storage	• UV radiation • Internal corrosion	Material ageing Metal loss
	Installation	• Transportation • Mechanical damages, overload, fatigue, deformation, HISC • Assembly shortcomings (e.g. incorrect bolt torque) • *Jointing of umbilical causing fatigue/compression (U)*	Yielding Collapse Cracking Loss of function
Material degradation	Corrosion	• Internal uniform corrosion • Environmental cracking • External corrosion due to CP system failure, lack of CP (loss of electrical continuity), excessive anode consumption causing lack of CP capacity • Galvanic corrosion • Flow induced corrosion • *Crevice corrosion due to seawater ingress unintentionally or intentionally (U)* • *Corrosion impact on steel armours when removing bitumen in umbilical (U)*	Metal loss Leak Burst Cracking Loss of function
	Coating degradation	• Formation of cold spots causing internal corrosion • Causing lack of CP capacity	Metal loss
	HISC	• Combination of excessive load, hydrogen and susceptible material	Crack Burst
	Material Ageing (degradation)	• Elastomeric seal ageing • Plastic creep • Faulty materials selection • Lack of UV resistance	Material ageing Leak Loss of function Collapse

Threat group	Threat - Examples	Threat description – Examples	Failure mode
		• Embrittlement of plastic materials having low resistance to UV-radiation • *Thermal ageing of umbilical internals caused by integrated high voltage cable (U)* • Embrittlement of materials exposed to low temperatures	Cracking
	Erosion	• Presence of sand • Flow condition	Metal loss Leak Burst Loss of function
	Wear	• High friction • Change of friction on hard faced seal surfaces • Galling e.g. due to incorrect torque of bolts • Loss of sealing • *Wear of umbilical tubes and outer protective sheath (U)*	Leak Loss of function Metal loss
	Cavitation	• Implosion of gas bubbles	Metal loss Leak
Internal medium	Change in fluid composition	• Impurities or contaminations in hydraulic fluid • Fluid incompatibility with materials • Use of incorrect hydraulic fluid Internal leaks (leak between systems) (e.g. control system leak	Metal loss Cracking Loss of function
	Change in reservoir condition	• Changes in well fluid composition (e.g. well souring, gas/water/oil composition changing production environment)	
	Injection chemicals	• Compatibility fluid/material,	
	Fluid incompatibility	• Hydraulic, compatibility fluid/material.	
	Well stimulation chemicals	• Compatibility fluid/material, ingress of fluid	
Third party	Trawling	• Trawl board impact • Trawl line snag	Burst Yielding Leak Cracking Collapse
	Anchoring	• Ship traffic	
	Dropped object		

Threat group	Threat - Examples	Threat description – Examples	Failure mode
	Mechanical impacts	• By intervention tools or ROV	Loss of function
	Vessel impact		
	Vandalism/terrorism		
	Traffic	• Vehicle impact, vibration	
Structural	Fatigue	• Due to VIV caused by waves, process variations, fluid hammer, slugging etc.	Burst Leak Cracking Collapse Yielding Loss of function Metal loss
	Excessive mechanical loads	• Due to pipeline/riser expansion, drilling, intervention, subsidence, well growth, scouring settlement, vibrations, over-torqueing, new tie-ins, XT retrieval, BOP loads, installation tolerances not accounted for in design	
	Excessive pressure loads	• Related to operation, fluid hammer	
	Excessive thermal loads	• Related to operation • *Axial tension (U)*	
	Temperature variations	• Temperature variations causing cyclic thermal expansion /retraction	
	Vibrations	• Promote fatigue	
	Loss of bolt tension	• e.g. Hang off arrangement for umbilical	
	Calcareous layer	• Unable to install or retract equipment, high resistance in electrical connections	
	Marine growth	• Unable to inspect equipment, increased load, installation delay, • *Excessive tension and increased dynamic behaviour (U)*	
	Local buckling	• *E.g. Umbilical excessive bending (U), axial compression (U)*	
	On bottom stability	• *Outer sheath damage (U)*	
	Twist	• *Outer sheath damage, excessive bending and axial compression (U)*	
	Burial	• *Insufficient burial depth or coverage of umbilical (U)*	
	Freespan	• *Frees pans due to sea currents, VIV (U)*	
Control system threats	Loss of power (electrical, hydraulic)	• Due to material degradation, low insulation resistance, water ingress (diffusion) resulting in short circuit, calcareous formation on mating surfaces, contamination on contact surfaces, cooling system failure	Loss of function Leak

Threat group	Threat - Examples	Threat description – Examples	Failure mode
	Sensor drift or failure	• Incorrect measurements	
	Communication error	• Loss of monitoring data or signals	
	Software failures	• Loss of communication	
Natural hazard	Extreme weather Earthquake Landslides Ice loads Volcanic activity	• Depends on location of the system	Burst Leak Cracking Loss of function
Operational	Incorrect operation	• Out of spec. operation, promotes wax and hydrate formation , increased risk for erosion due to sand, out of spec. flow, pressure, temperature, blow down, oxygen content • *Excessive pressure, insufficient cooling topside (U)*	Clogging Metal loss Yielding Collapse Loss of function Material ageing
	Incorrect procedures	• Procedures not updated according to changes in operation	
	Human errors	• Overfamiliarity (e.g. ignored alarms), lack of training, lack of experience transfer	

Table A- 2 Failure modes

Failure mode	Description	Cause (damage abnormality)	Consequence	Degradation mechanisms
Burst	Failure due to loss of pressure containment	Wall thinning, crack propagation, overload, metal loss, sand	Large spill	Corrosion, erosion fatigue
External leak	Failure jeopardizing system pressure containment	Localized corrosion attack, small crack, damaged seal, loss of external corrosion protection	Small spill	Material ageing corrosion, erosion fatigue
Metal loss	Reduction of system pressure containing capacity	Coating damage, wall thinning	Wall thinning reduced load bearing capacity	Corrosion erosion
Cracking	Fracture capacity exceeded	Overload, vibrations	Large spill	HISC, environmental cracking, fatigue
Yielding	Too high utilisation of the material due to overload	Dent, overload, displacement	Loss of function, loss of functionality	Corrosion, erosion
Collapse (Buckling)	Deformation of the cross section or full collapse	External overload, deformation	Loss of or reduced function	Corrosion, erosion
Loss of function	Loss of or reduced function; Control system failure or component failure preventing equipment to operate as intended.	Ovalisation, deformation, control system failure due to internal or external leak, diffusion	Loss of functionality, loss of power (electrical/hydraulic), loss of function, overheating	Material ageing corrosion HISC environmental cracking
Material ageing	Delamination of polymeric materials reducing e.g., strength or protective capability. Ageing of elastomeric material due to chemical and thermal exposure	Material degradation due to exposure to conditions outside of qualified range e.g. UV, temperature, chemicals	Loss of function, internal and external leak	Ageing
Internal leak	Isolated components not able to fulfil its function	Material ageing, ovalisation, deformation	Loss of function, loss of sealing capability, contamination, hydrate formation	Corrosion, material ageing, wear
Clogging	Clogging of piping or equipment preventing fluid flow	Wax or hydrate formation due to incorrect operation	Loss of function, loss of functionality	

Table A-3 Organisational threats

Threat group	Threat - Examples	Threat description – Examples
Organisation	Lack of resources	• Lack of training • Lack of in-house qualified personnel
	Use of temporary personnel, high labour turnover	• Lack of experience • Discontinuity in work • Difference in decision making • Lack of proper document handover
	Procurement	• Contract requirements not in compliance with project requirements • Purchasing not according to specifications
	Lack of procedures	• Not able to operate according to intended purpose
Integrity management system	Unidentified threats Insufficient inspections, monitoring and testing	• Lack of or incomplete integrity management system
Documentation	Lack of, incomplete or incorrect documentation	• Lack of system for handling life cycle information • Insufficient handover of essential documentation from design to operation.

APPENDIX B
Abbreviations

Acronym	Definition
BOP	Blowout Preventer
BSEE	Bureau of Safety and Environmental Enforcement
CAPEX	Capital Expenditures
CBM	Choke Bridge Module
CFD	Computational Fluid Dynamic
CNOOC	China National Offshore Oil Corporation
CMMIS	Computerized Maintenance Management Information System
CODAM	Corrosion Damage
CP	Cathodic Protection
CPM	Condition and Performance monitoring
CRA	Corrosion Resistant Alloys
CS	Carbon steel
Cv	Coefficient value
DEH	Direct Electric Heating
DFI	Design, Fabrication and Installation
DFO	Documentation for Operation
EPCI	Engineering, Procurement, Construction and Installation
ESP	Electro Submersible Pump
FCM	Flow Control Module
FPSO	Floating Production, Storage and Offtake Vessel
FPS-Semi	Floating Production System (*FPS*) *Semi*-Submersible
FPU	Floating Production Unit
FSO	Floating Storage and Offtake
FPDSO	Floating Production Drilling Storage and Off- Loading
GOM	Gulf of Mexico

GVI	General Visual Inspection
HAZID	Hazard Identification
HIPPS	High Integrity Pipeline Protection System
HISC	Hydrogen Induced Stress Cracking
HP	High Pressure
HCR	Hydrocarbon Releases Database System
HSE	Health, Safety and Environment
HT	High Temperature
HXT	Horizontal XT
IM	Integrity Management
IMR	Inspection Maintenance and Repair
IMS	Integrity Management System
IOC	International Oil Company
JIP	Joint Industry Project
KBS	Kværner Booster Station
LIC	Life Cycle Information
MCM	Manifold Control Module
MEG	Mono Ethylene Glycol
MIC	Microbiological Influenced Corrosion
MMS	Minerals Management Service
Mudline XT	Early term for a subsea tree. Can be either horizontal or vertical trees but is more often a vertical tree.
NCS	Norwegian Continental Shelf
NOC	National Oil Company
NPD	Norwegian Petroleum Directorate
OCS	Outer Continental Shelf
OLF	Oljeindustriens Landsforening (renamed: Norsk Olje & Gass)
ONGC	Oil and Natural Gas Corporation
PAC	Pacific

PARLOC	Pipeline and Riser Loss of Containment
PIM	Pipeline Integrity Management
PMV	Production Master Valve
PSA	Petroleum Safety Authority
PWV	Production Wing Valve
RGD	Rapid Gas Decompression
ROV	Remote Operated Vehicle
RP	Recommended Practice
SAR	Safety Assessment Report
SCM	Subsea Control Modules
SDU	Subsea Distribution Unit
SIMS	Subsea Integrity Management System
SIS	Safety Instrumental System
SPS	Subsea Production System
TLP	Tension Leg Platform
UV	Ultra Violet
VSD	Variable Speed Drives
VXT	Vertical XT
WOAD	Worldwide Offshore Accident Databank
XT	X-mas Tree

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