Chair of Petroleum and Geothermal Energy Revovery

Master Thesis

Subsea Production Systems - A Review of Components, Maintenance and Reliability

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Trondheim, 09 September 2016

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Acknowledgment

This work was completed during an ERASMUS+ Traineeship at the Department of Production and Quality Engineering at NTNU, Faculty of Engineering Science and Technology, from January to June 2016.

I am truly grateful to Anne Barros, Professor in Subsea Reliability at the Department of Production and Quality Engineering at NTNU, for offering me the opportunity to carry out this research. Her involvement and supervision were of inestimable value to successfully complete this work. Additionally, her contribution to the SUBPRO centre for research based innovation offered a framework to conduct this thesis.

I would also like to express my gratitude to Univ.-Prof. Dipl.-Ing. Dr.mont. Herbert Hofstätter, Head of Chair of Petroleum and Geothermal Energy Recovery at Montanuniversität Leoben, who was willing to accept my thesis proposal and to support my stay at NTNU.

Furthermore I am thankful for all the support I received from OMV. At this point I want to especially mention my mentor Werner Liebl.

Finally, I would like to thank my family and friends for their support. Even though you might think you contributed just very little, your support has been of great value to me on the path that led me to where I am today. Especially I want to thank Nobbi and Tufl – without your influence I would probably never have found myself in the situation to write these words.

Thank you Inge for making me feel at home whenever I am with you.

C.M.

Kurzfassung

Für die Entwicklung von offshore Kohlenwasserstoff-Vorkommen stellen *Subsea Production Systems* (zu Deutsch wörtlich: Unterwasser-Produktions-Systeme) eine zunehmend interessante Alternative dar. Ihre Vorteile bei der Erschließung entlegener und verhältnismäßig kleiner Lagerstätten werden ebenso geschätzt wie die Freiheit in der Platzierung der Produktionsbohrungen. Aus ökonomischen Gründen werden auch immer mehr Sub-Systeme entlang der Produktionskette am Meeresgrund installiert. Eingriffe zur Wartung und Reparatur solcher Installationen sind allerdings kostenintensiv, daher ist die Zuverlässigkeit des Systems von großer Bedeutung.
Diese Arbeit beschreibt *Subsea Production Systems*, mögliche Wartungsstrategien und gibt einen Einblick in die Bewertung der Zuverlässigkeit solcher Systeme. Basierend auf einer Literaturrecherche wird eine Definition eines *Subsea Production Systems* gegeben und dessen Zweck sowie die einzelnen Bestandteile näher beschreiben. Möglichkeiten für die Überwachung des Systemzustandes bzw. der Zustände der Einzelkomponenten werden aufgezeigt. Zusätzlich wird die Bedeutung von *Subsea Production Systems* für die Entwicklung von offshore Kohlenwasserstoff-Vorkommen skizziert und ihre Bedeutung für Investitionsentscheidungen hervorgehoben.
Des Weiteren präsentiert diese Arbeit einen Überblick über Wartungskonzepte für und deren Anwendung an *Subsea Production Systems*. Außerdem werden störanfällige Komponenten und deren Schadensarten beschrieben. Wartungsorganisation und –aktivitäten, welche in der Industrie zum Einsatz kommen, werden vorgestellt. Eine Analyse der Sicherheitsfunktion *“Isolate the subsea well from the flowline by closing the production master valve”* (Absperren des Bohrlochs durch Schließen des Hauptventils) wurde durchgeführt um deren Zuverlässigkeit zu beziffern. Dafür wurde ein Fehlerbaum entwickelt um alle Fehlerquellen und deren Abhängigkeit darzustellen, die einen möglichen Fehler der Funktion verursachen könnten. Die berechnete durchschnittliche Frequenz gefährlicher Fehler pro Stunde betrug 8.56×10^{-6} über einen Einsatzzeitraum von 20 Jahren. Daraus resultiert ein Sicherheitsintegritätslevel von 1 und somit die Erfüllung der Normvorgabe. Aus dem Ausmaß, in welchem einzelne Fehlerquellen zu diesem Ergebnis beitrugen, konnten Empfehlungen für die Überwachung des Systems abgeleitet werden. Daher wird eine Überwachung des *pressure*

regulators (Druckausgleichventil), der *subsea umbilical termination assembly* (Unterwasseranschlusseinheit der Versorgungsleitung), des *surface pilot valves* (Steuerventil) und elektrischen und elektronischen Komponenten vorgeschlagen.

Abstract

In offshore hydrocarbon developments subsea production systems become a more and more favoured alternative. Their ability to develop remote and marginal resources as well as increased freedom in placement of subsea wells compared to traditional systems is appreciated. For economic reasons the trend is to place sub-systems along the production chain increasingly subsea. However, intervention, maintenance and repair activities associated with such installations are costly. System reliability is therefore of great importance.

This thesis describes subsea production systems, feasible maintenance strategies and gives an insight in reliability assessment. Based on a literature study a definition of subsea productions systems is given and their purposes and components are described. Ways for monitoring the system's state and the one of single components, respectively, are pointed out. Furthermore, the role of subsea production systems in the development of offshore hydrocarbon resources is outlined and their importance for project investment decisions highlighted.

This thesis furthermore presents an overview of maintenance concepts for and their employment on subsea production systems as well as failure prone items and common failure modes. Additionally maintenance organisation and activities as practised in the industry are featured.

An analysis quantified the reliability of the safety function "Isolate the subsea well from the flowline by closing the production master valve". Therefore a fault tree was developed to picture basic events and their interdependence in leading to possible failure of the function. The calculated average frequency of dangerous failures per hour was 8.56×10^{-6} over a mission time of 20 years. This resulted in a safety integrity level of 1 therefore fulfilling the requirement of the industry standard. From the contributors to this result propositions for how to monitor the system in order to ensure the realisation of the system's inherent reliability could be deduced. The monitoring of the pressure regulator, the subsea umbilical termination assembly, the surface pilot valve, and electric and electronic components was therefore suggested.

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Abbreviations

AUV autonomous underwater vehicle

BOP blow-out preventer

CAPEX capital expenditure

CBM condition based maintenance

CM condition monitoring

CPM condition and performance monitoring

CVM control valve module

DCV direction control valve

ESP electric submersible pump

EUC equipment under control

E&P Exploration & Production

FMECA failure mode effect and criticality analysis

FPSO Floating Production Storage and Offloading

FTA Fault tree analysis

GoM Gulf of Mexico

HA hydraulic actuator

HAZID hazard identification

HAZOP hazard and operability study

HSE health, safety and environment

HXT horizontal tree

HPU hydraulic power unit

I position indicator

IMR intervention, maintenance and repair

IO integrated operations

KPI key performance indicator

MCU multicore umbilical

MFP minimum facility platform

MUX E/H multiplexed electro-hydraulic

NCS Norwegian Continental Shelf

ODBC open database connectivity

OPEX operational expenditure

OREDA Onshore and Offshore Reliability Data

PCS production control system

PFD probability of (dangerous) failures on demand

PFH average frequency of dangerous failures per hour

PGB permanent guidebase

PM preventive maintenance

PMV production master valve

PSU power supply unit

RBI risk-based inspection

RCM reliability centred maintenance

ROI return on investment

ROT remotely operated tools

ROV remotely operated underwater vehicle

RUL remaining useful lifetime

SCM subsea control module

SCU surface control unit

SEM subsea electronic module

SIF safety instrumented function

SIL safety integrity level

SIS safety instrumented system

SPS subsea production system

SSP subsea processing

SUTA subsea umbilical termination assembly

TCI technical condition index

TGB temporary guidebase

TH tubing hanger

TLP Tension Leg Platform

VSD variable speed drive

VXT vertical tree

WH Wellhead

XT Christmas tree

Nomenclature

C_v flow coefficient

$\mathbf{I^B(i|t)}$ Birnbaum's measure of importance of component i at time t

$\mathbf{w_i(t)}$ unconditional rate of occurrence of the basic event i

$\mathbf{Q_0(t)}$ probability that the TOP event occurs at time t

$\mathbf{q_i(t)}$ probability that the basic event i occurs at time t

$\lambda_{\mathbf{D,i}}$ rate of dangerous failures of the basic event i

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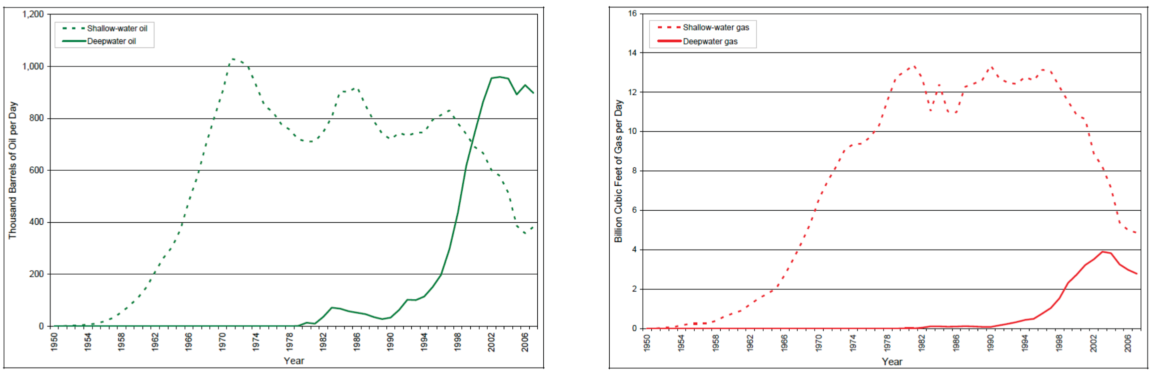
Chapter 1

Introduction

1.1 Background

In the constantly rising demand for energy hydrocarbon resources are acting as the backbone of global energy supply. In 2013 55% of the world's total final energy consumption was provided by oil and natural gas [1]. Hydrocarbon resources are developed onshore as well as offshore in many areas of the globe. For the stability of the world's energy supply new prospects need to be discovered and subsequently explored as todays reserves are getting constantly depleted. These tend to lie in harsh environments and are often situated offshore, thereby in increasing distances from the coast and in ever deeper waters. Figure 1 presents recent trends in offshore hydrocarbon production.

Besides the Gulf of Mexico (GoM) in North America, Europe's North Sea, the South Atlantic Ocean offshore Brazil and the west coast of Africa are areas with high offshore activity. In such developments subsea production systems (SPS) become an increasingly popular option. These systems allow for higher flexibility in well placement as they do not necessarily have to be deployed directly under an offshore structure such



(a) average annual oil production (b) average annual gas production

Figure 1: Average annual hydrocarbon production, Gulf of Mexico [2]

as a platform or ship. This may also offer the opportunity for developing marginal and remote resources. Global subsea capital expenditure (CAPEX) from 2004 to 2014 as well as an forecast until 2020 can be seen in Figure 2.

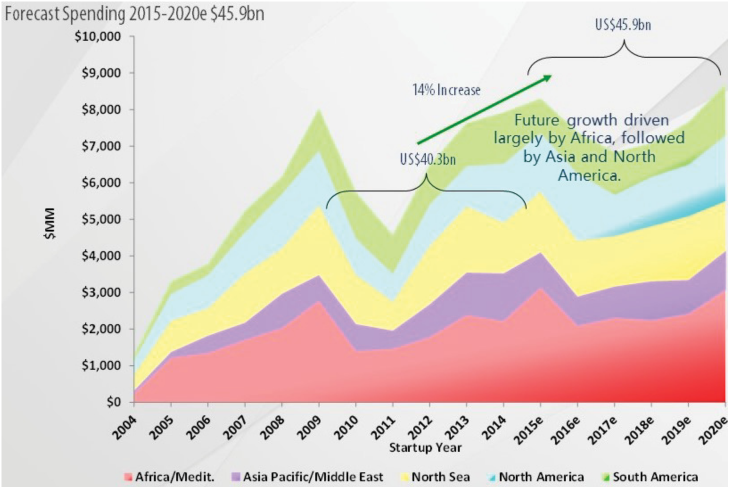


Figure 2: Global subsea CAPEX [3]

When it comes to intervention, maintenance and repair (IMR) activities for SPSs, skilled workers, equipment and logistics are of concern. This issue has been described in [4] and the associated cost factors have been intensively discussed in [5]. Furthermore, new generation systems are increasingly complex as more and more facilities along the production chain are placed subsea. Reliability of SPSs therefore becomes increasingly important for both environmental and economic reasons.

Research centres like SUBPRO, which is based at NTNU, focus on the particular requirements, challenges and opportunities which arise from moving more processing subsea. One of the key challenges identified is subsea systems engineering and operation, which includes monitoring and prediction of equipment and system state (wear, degradation, fouling, leaking,. . .). In order to carry out research in these areas it is necessary to understand the framework of SPSs. Thus, the following questions arise:

- What components are involved in SPSs?
- Which of these are prone to failure and what sort of failure modes occur?
- What kind of data can be used for planning maintenance and how?
- How are maintenance and intervention tasks currently organized in the industry?
- What are limiting factors in terms of reliability as well as maintenance of the system?

This applied literature overview will address the questions mentioned above. Standards as [6] provide general requirements and recommendations for SPSs and their subsystems. In addition, SPSs have to comply with further standards and regulations. IEC 61508-1 [7], IEC 61511 [8] and NOG-070 [9] embody the most relevant guidelines when it comes to functional safety. Theoretical principles of reliability engineering mentioned in Rausand and Høyland [10] and Rausand [11] provide the foundation of the method which has been applied for quantifying reliability.

1.2 Objectives

The main objectives of this thesis are:

1. Describe SPSs (including subsystems and components), document the purposes of the equipment and show the interaction between the different parts of the system
2. Provide an overview of maintenance concepts for SPSs, reveal common problems and give an insight in industry practices
3. Show the potential for condition monitoring (CM) within a SPS

1.3 Limitations

The subject of this study is a SPS, which's scope is described in section 2.1. It is therefore confined by the reservoir on one side and by the interface to storage or transport to a purchaser on the other. Thus, it does not involve transport facilities such as pipelines. This thesis considers maintenance to be an activity related to parts of the SPSs but not the reservoir. However, both types of activities may still be carried out during the same single intervention. Moreover, all aspects related to CM mentioned in this thesis concern the monitoring of components of a SPS unless otherwise stated. This has to be clearly dissociated from monitoring of reservoir performance which is widely done in oilfield operations.
General limiting factors in this research are the availability of and the access to literature regarding the topics discussed. In case of the analysis that has been carried out there was only a single data source for failure rates available [12]. That covered the failure modes of interest just partly. Additionally, no human factors are considered in the performed analysis.

1.4 Approach

Objectives 1 and 2 (see 1.2) have been addressed each by first carrying out and subsequently documenting a literature review. These reviews have been done by utilising the university library collections of both Montanuniversität Leoben and NTNU. For objective 3 a reliability analysis has been performed first using the demo version of the CARA FaultTree software. This analysis has been used afterwards to assess the reliability performance of a system function. That has been achieved by quantifying the measure of average frequency of dangerous failures per hour (PFH) which is part of the safety integrity concept. Therefor failure rates from SINTEF et al. [12] have been used.

1.5 Structure of the Report

Subsequent to this introductory chapter the fundamentals of subsea production systems are described in chapter 2. Apart from touching on the special applications of SPSs, the main focus of that chapter lies on the technical description of the system's elements. Additionally, health, safety and environment (HSE) aspects are discussed. In chapter 3 different concepts for maintenance are introduced and their application for SPSs is characterised. A practical perspective on the organisation of maintenance for SPSs is also given. Moreover a quantification of the reliability performance of a subsystem has been carried out and is reported in chapter 4. The method and the actual analysis are described followed by the statement and discussion of the results. The concluding chapter 5 summarises the research conducted and gives suggestions for possible future work.

Chapter 2

Fundamentals

This chapter is intended to introduce the reader to the topic of SPSs. It presents the findings of a literature study carried out on this topic. Additional to an overview of typical system components these provide an understanding for the need of subsea production systems and also give a brief insight in the history of such systems, as well as examples of successfully carried out projects. Moreover possible alternatives are discussed.

2.1 Definition

A production system is ”the system that transports reservoir fluids from the subsurface reservoir to the surface, processes and treats the fluids, and prepares the fluids for storage and transfer to a purchaser” [13]. Hence, *Subsea* Production Systems are systems of the same kind with the distinction of being placed below the water surface. The extent may thereby vary, meaning the whole system could be placed under water or only parts of it.
The special environment subsea demands ”some unique aspects related to the inaccessibility of the installation and its operation and servicing.” [14]. Concerning system architecture, a subsea production system ”consists of a subsea completed well, seabed wellhead, subsea production tree, subsea tie-in or flowline system, and subsea equipment and control facilities to operate the well.” [15]. Furthermore the National Petroleum Council in 2011 notes that in a subsea completion ”the producing well does not include a vertical conduit from the wellhead back to a fixed access structure.” [16]
ISO 13628-1 [6] describes the system characteristics as follows: ”Subsea Production Systems can range in complexity from a single satellite well with a flowline linked to a fixed platform or an onshore installation, to several wells on a template or clustered around a manifold producing via subsea processing/commingling facilities and trans-

ferring to a fixed or floating facility, or directly to an onshore facility." These facilities are commonly referred to as *host facilities*. Furthermore, these host facilities may be "a fixed, bottom-founded structure (e.g. a steel-piled jacket or a concrete gravity structure) or a floating structure, i.e. either a tension-leg platform or a floating production system (e.g. a ship, semi-submersible or spar)." according to [6].
In some cases, the terms dry and wet (tree) system are used related to offshore installations. A dry tree allows "for the wellheads and Christmas tree valve systems to be above the waterline (i.e. in the dry)." [17]. This facilitates well-access for maintenance and re-entry on a continuous basis. Offshore facilities like conventional jackets, spars, and tension leg platforms (TLPs) may host such a dry tree. A dry tree system is not to be confused with a "dry subsea system", also referred to as subsea atmospheric system. Such systems have "some or all subsea components encapsulated in a sealed, one atmosphere chamber." [15].
However, wet technology is the approach that has solely been used in recent years [18]. This thesis focuses on SPSs comprising wet tree systems, also known as subsea completions, where "the wellheads and Christmas trees are placed on the seabed." [17].

2.2 Evolution of Subsea Production Systems

In 1961 a subsea completion was installed in the GoM in a water depth of 55ft (about 17m), making it the world's first. Subsequently, full-field subsea developments were carried out in the GoM and offshore California and over time a solid basis of experience was established. This was of great value when subsea developments in the North Sea came on stream. Especially know-how for diver-less deepwater technology was transferred across the ocean. The early production system in the Ekofisk field installed in 1971 symbolises not only the first North Sea field development, but was also the first time subsea wells were used in the North Sea. Brazil, where the majority of subsea developments are carried out in the Campos basin, represents another big application area for SPSs behind the North Sea. Here, the first wells were completed subsea in 1977 in the Enchova field. Among the innovations that have first been tested in Brazil are the layaway technique for subsea trees, standardisation of subsea equipment, and equipment reuse. [18]
Today, the world's deepest installed subsea tree is located in the Tobago field, about 200miles (about 322km) south of Freeport, Texas in the GoM. The wellhead is located in a water depth of 2934m. Tobago is operated by Shell and produced through the Perdido drilling and production platform. [19, 20]
The record for the world's longest tie-back producing oil is just short of 70km. The

Penguin cluster consisting of A-E fields in the North Sea are tied-back to the Brent C platform, both operated by Shell Expro (a Shell and ExxonMobil joint venture). [19, 21]
In case of a gas producing tie-back the length record is held by Noble Energy's Tamar field, 80km west of Haifa in the Mediterranean Sea. The subsea wellhead is tied back 150km to the host facility, the Tamar platform. [19, 22]
One important contributor in this progression towards more remote locations is subsea processing (see also Chapter 2.4.4). Subsea boosting in the form of a cyclone separator combined with an ESP is used in the Perdido development. Both the world's first subsea wet-gas and dry-gas compressors have been started in 2015 in the Gullfaks and the Åsgard field, respectively [23, 24].
Another noteworthy development is the *Statoil Subsea Factory™* concept. For increasing the economic value of offshore field developments, it aims to "combine and reuse in a new way the subsea production and processing technologies already installed or being constructed in Statoil." [25]. Therefore, a system approach from reservoir to export system also including the transport of multiphase fluid over long distances, floating production facilities as well as pipeline networks is utilised. Statoil's ambition is to efficiently develop fields with longer step-outs from shore ore existing facilities, which are located in deeper waters or harsher environments. Additionally Statoil seeks to be able to prolong operations of existing fields and infrastructure. The targets for different types of fields are summarised in Table 1.

Table 1: Target ambitions for realisation of subsea factory, from [25]

	Gas / condensate fields	Oil fields	Heavy oil fields
Longer transport	250 km	200 km	50 km
Longer power	100 MW	20 MW	50 MW
Deeper	3000 m	3000 m	2000 m
Colder (environment)	Under ice	Under ice	Harsh environment
Colder (heavy/complex fluids)	Sour/Acid Gas issues	Cold flow	Cold transport

For these purposes, new technology elements, such as subsea storage facilities (for oil and chemicals), have to be developed and qualified. An illustration of the Subsea Factory™ concept is given in Figure 3.

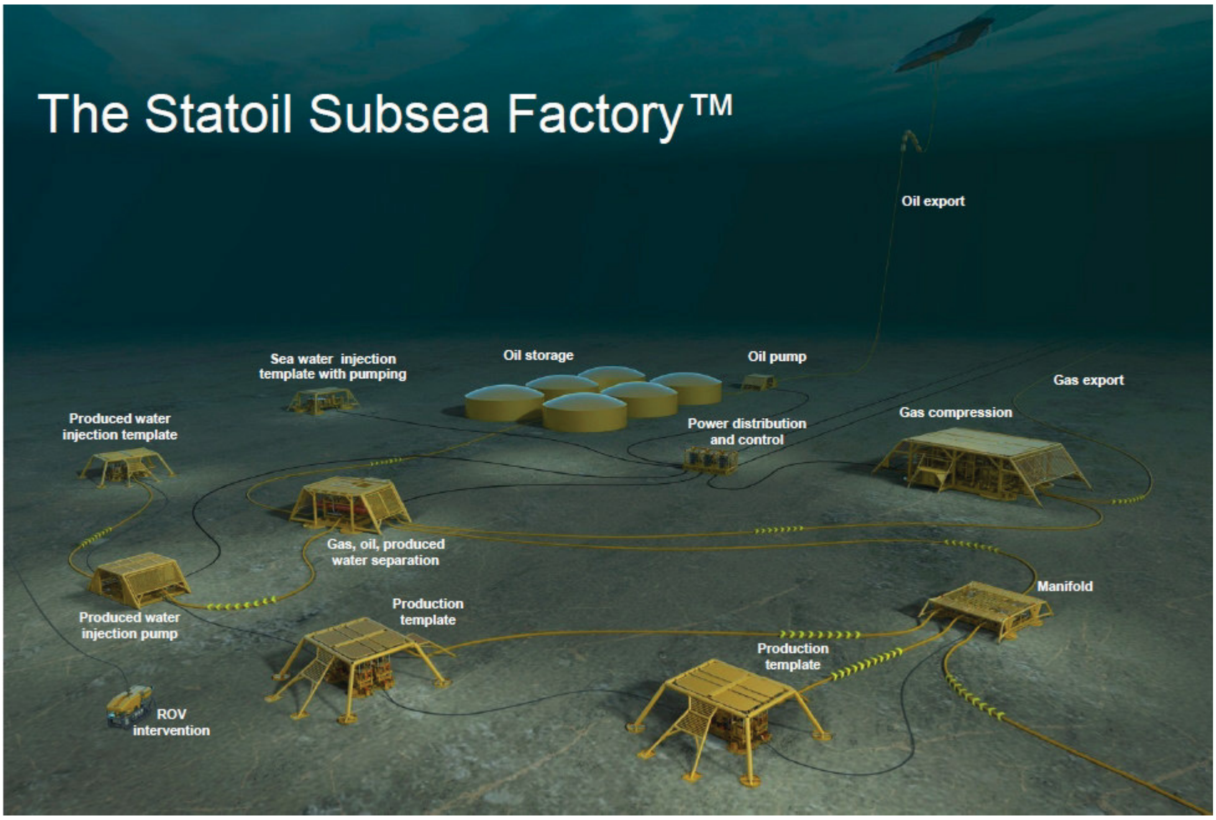


Figure 3: The Statoil Subsea Factory™, from [25]

Deployment of the subsea compression systems in the Gullfaks and Åsgard field, as mentioned above, is part of Statoil's goal to realise a complete subsea factory by 2020.

Parallel to these developments pushing boundaries further, utilisation of simple and cost effective systems in shallower waters has increased in recent years. Hansen and Rickey [18] stated that installations in water depths shallower than 400ft (about 121m) a total of 243 wells between 1985 and 1995 - corresponding to 52% of the overall number of installed wells.

2.3 Applications of Subsea Production Systems

Several drivers for the utilisation of SPSs can be distinguished:

Extended Reach

Platform operations are limited to the horizontal reach of their wells. For the Statfjord and Gullfaks fields in the North Sea, where drilling started in 1978 and 1985 respectively, an initial design limit for wellbore inclination was set at 60°. This was a trade-off provoked by drilling problems (mainly due to lacking proper understanding of wellbore stability and hole cleaning) and technological limitations.

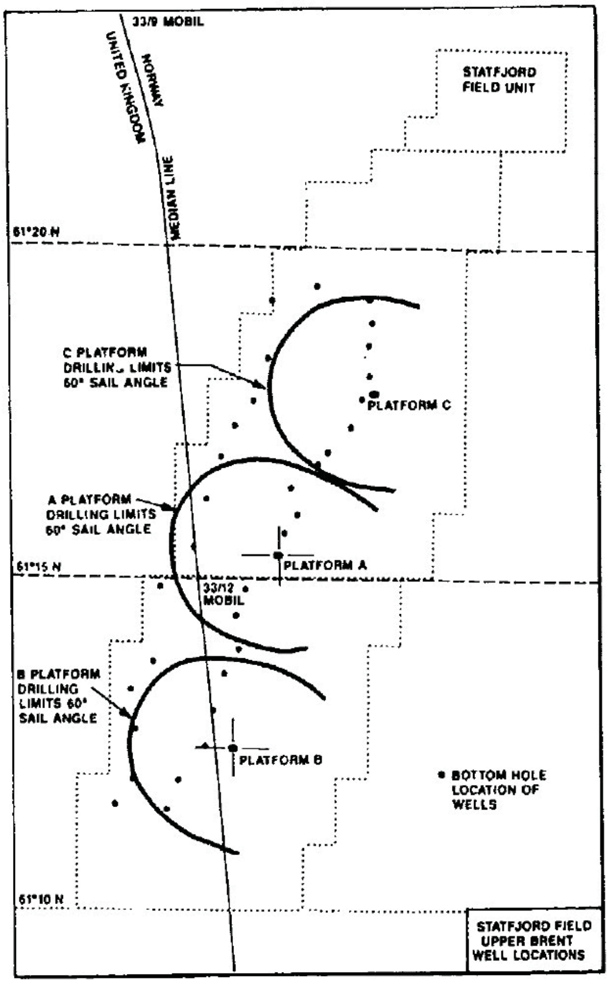


Figure 4: Statfjord Field - maximum 60° Boundary Profile, from [26]

In each field three platforms where positioned for maximum coverage of the reservoir area according to the sail angle as shown in Figure 4. Yet, that left dead areas in between the platforms and missing the opportunity to produce or inject at the flanks of the reservoir. Subsea wells where therefore considered as an alternative [26, 27, 28].

Although drilling technology has advanced since then the need is still present today. In some fields individual parts of the reservoir may lie in a depth or be of such geometry that they are not easily accessible from an existing platform.

Marginal Fields

Smaller reserves often cannot economically justify the use of platforms because of their limited production potential. This is a classical application of subsea production systems. The completed wells are either tied back to an existing offshore facility or (in case there is no facility nearby) a Floating Production Storage and Offloading (FPSO) unit. Examples for such developments are the East Frigg field [29] and the Tommeliten [30] field on the Norwegian Continental Shelf (NCS).

Satellite Fields

Offshore platforms are deployed at a position that allows optimum access to reserves. The decisions on these positions are taken in an early stage of the field development. Knowledge about the reservoir is often limited in that phase of the project. During the lifetime of a field the reservoir model is continuously updated with new data gained. This improved understanding of the reservoir may lead to a recognition of yet untouched reserves. In case these additional reserves are beyond the drilling reach of the initially deployed platforms subsea wells are often used to tap these reserves. The wells are then tied back to the existing facilities. This has been the case for the Statfjord satellite fields at the U.K.-Norwegian boundary of the North Sea. [31]

Early Revenues

Subsea production systems can often be designed, fabricated and installed faster than platform solutions - especially when re-entering exploration wells. In that case they are also referred to as early production systems since they allow a significant reduction of the time-span between discovery and start-up. This time saving ensures early production, hence early revenues. That is especially facilitating when time, contractual or lease requirements have to be met. Subsea production systems have been successfully used for that purpose in the Nemba Field offshore Angola or in the Campos Basin offshore Brazil [32, 33].

Well Testing and Reservoir Evaluation

A Subsea production system can be used to gather additional information about the reservoir. The gained test and/or production data can be used to evaluate the potential for development of the reserve. Extended production testing has a high benefit-to-cost-ratio as it reduces reservoir uncertainties and allows for accurate design of field installations. Long-term increase in profitability as well as the revenue from early hydrocarbon production during the testing contributes to recovering the costs of the operation. [32, 34, 35, 36]

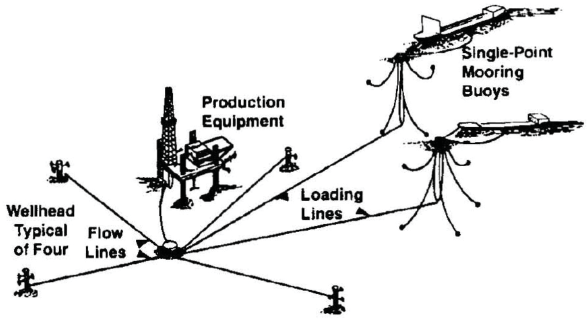


Figure 5: Ekofisk early production system, from [18]

Initiated in 1971, the Ekofisk early production system as shown in Figure 5 was used for an extended test to gain reservoir performance information and early cash-flow. [18]

Deepwater Developments

For deepwater developments with a small number of wells, SPSs are often favoured. Additionally, there is a limit in operation depth for fixed platforms, from both an economic as well as an engineering point of view [17]. Then, SPSs are tied-back to floating structures. They can be conducted as extended reach wells, directly under the facility, or both. [15]

Special Applications

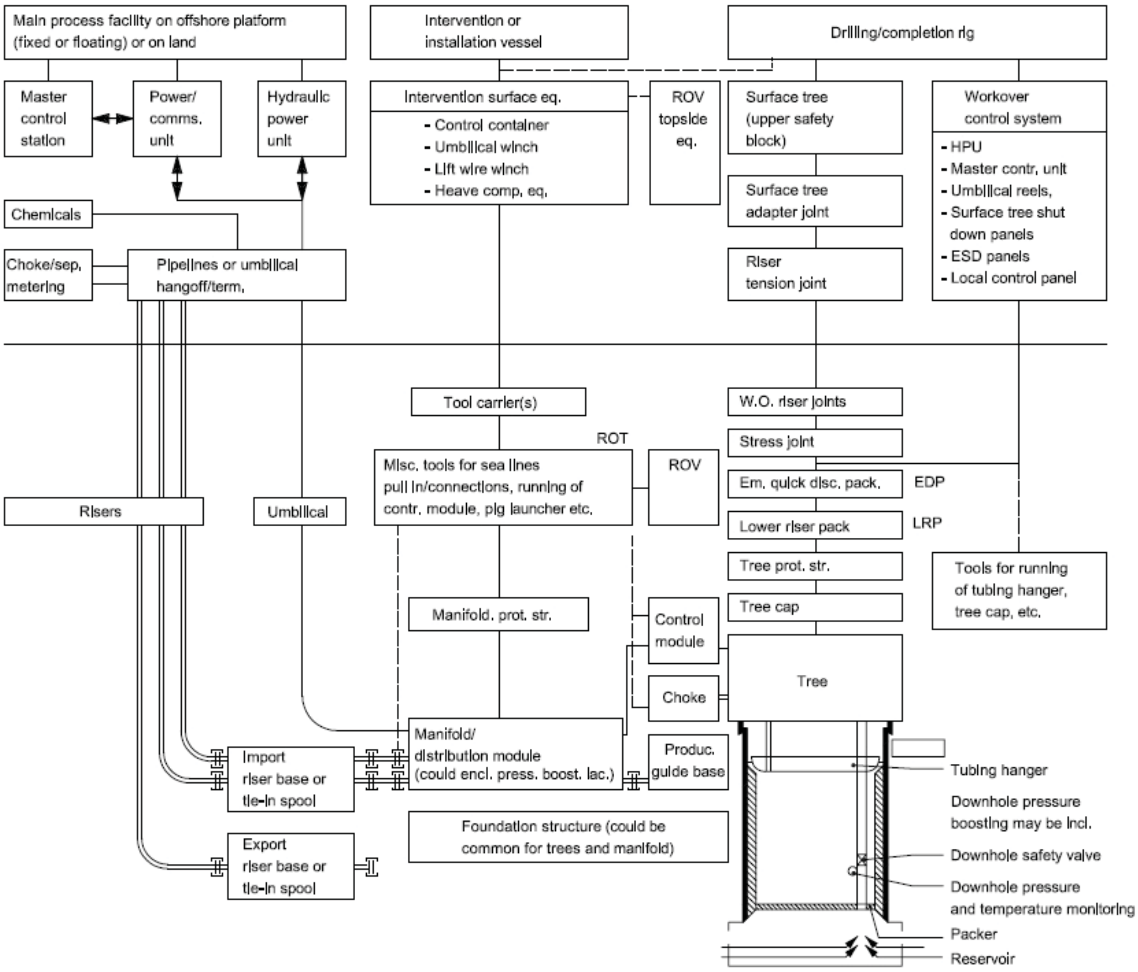
In very shallow waters (in the case referred to: 9m), SPSs may be utilised to allow marine traffic directly above the installation, which would obviously not be possible with any other facility. Caisson structures recessed into the seabed may be used to allow for additional clearance. [37]
SPSs may also be installed in so-called glory holes, excavated depressions on the seafloor, so that icebergs can pass over without interfering with the subsea facilities [38]. In combination with weak link technology flowlines this yields a proven technology to ensure safe all-year production in ice infested waters, e.g. offshore Newfoundland [39].

2.4 Subsea Production System Components

In general, a subsea production or injection system comprises one or more of the following parts [6]:

- a wellhead with connected casing strings;
- a subsea tree comprising pressure- and flow-control valves;
- a template as structural foundation for support and positioning of different equipment;
- a manifold system for channelled gathering and distribution of multiple fluid streams;
- subsea processing equipment, including fluid separation devices and/or pumps compressors and associated electrical power distribution equipment;
- a production control and monitoring system for remote monitoring and control of various subsea equipment, possibly including multi-phase flowmeters, sand detection meters, leak detection devices;
- a chemical injection system;
- an umbilical with electrical power and signal cables, as well as conduits for hydraulic control fluid and various chemicals to be injected subsea into the produced fluid streams;
- one or more flowlines to convey produced and/or injected fluids between the subsea completions and the seabed location of the host facility;
- one or more risers to convey produced and/or injected fluids to/from the various flowlines located on the seafloor to the host processing facilities;
- well entry and intervention system equipment, used for initial installation and abandonment of the subsea equipment, as well as for various maintenance activities on the subsea wells.

The parts of the system are schematically illustrated in Figure 6. A SPS may be assembled in different ways depending on location and field development strategy. Numerous combinations of the system elements can be arranged and combined with others.



NOTE For satellite wells directly tied back to the platform, several of the above-mentioned elements are eliminated.

Figure 6: Typical elements in a subsea production system, from [6]

2.4.1 System Configuration

Satellite Well

A single subsea well that is tied in to a host facility with adequate infrastructure is called a satellite well. Utilisation may often be the case for targets beyond the drilling reach of the host facility (in case that is a drilling and production facility) or for developments of small size. These may consist of several satellites. [6, 14]

Daisy Chain

A daisy chain configuration is a connection of various satellite wells in series. On one hand such a set-up may allow for cost savings since they all produce into a single flowline. On the other hand this configuration comes at the risk of flow assurance issues as the last well in the chain may produce into an oversize flowline. Also multi-phase flow-metering devices in combination with chokes on every single well may be necessary to ensure adequate flow allocation. [6, 14]

Cluster

In a cluster arrangement a number of single satellite wells are tied-in to a manifold. This device is used to gather and distribute fluids and is placed in proximity to the tied-in wells preferably in a central location. Produced hydrocarbons are fed into a common flowline that connects the manifold with the host facility. Fig 7 shows a typical manifold where two common production flowlines are used. This configuration allows for operating different wells at different pressure levels, testing, as well as flowline pigging. [6, 14]

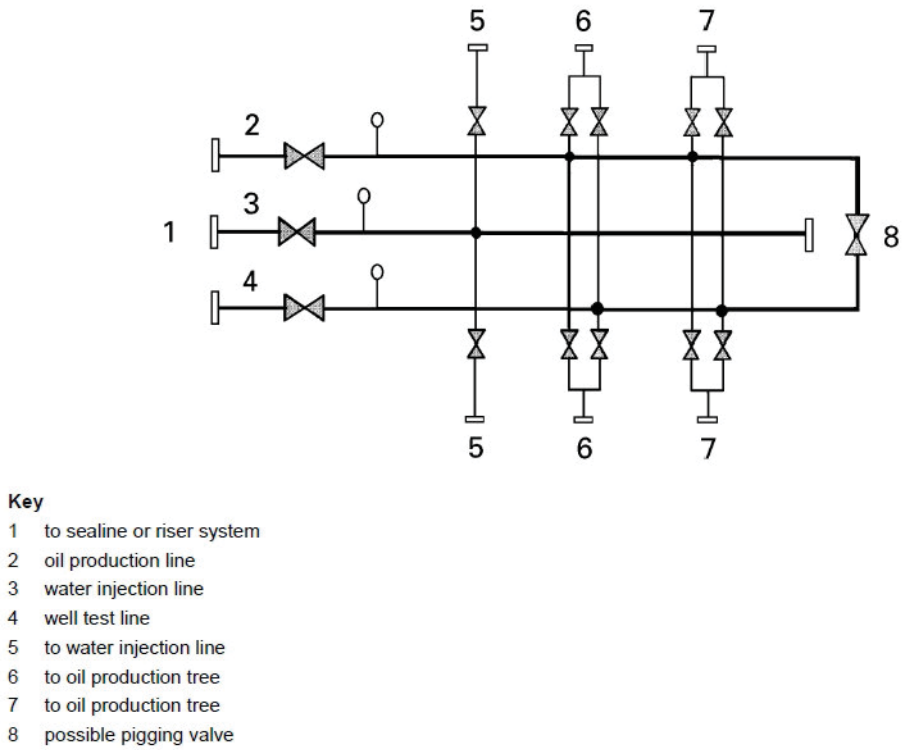


Figure 7: Manifold schematic, from [6]

The manifold itself holds valves to control the fluid flow, and may also hold additional control devices (e.g. chokes) in case these are not part of the single subsea trees. The size of a manifold is limited by the moonpool of the deploying vessel. Therefore clusters typically comprise of four to six wells only. These clusters can be tied back to a host facility individually or again be daisy-chained together. Unlike templates, as described subsequently, this system offers flexibility regarding well placement (e.g. for reasons of drilling purposes) as well as concurrent drilling and production. [6, 14]

Template

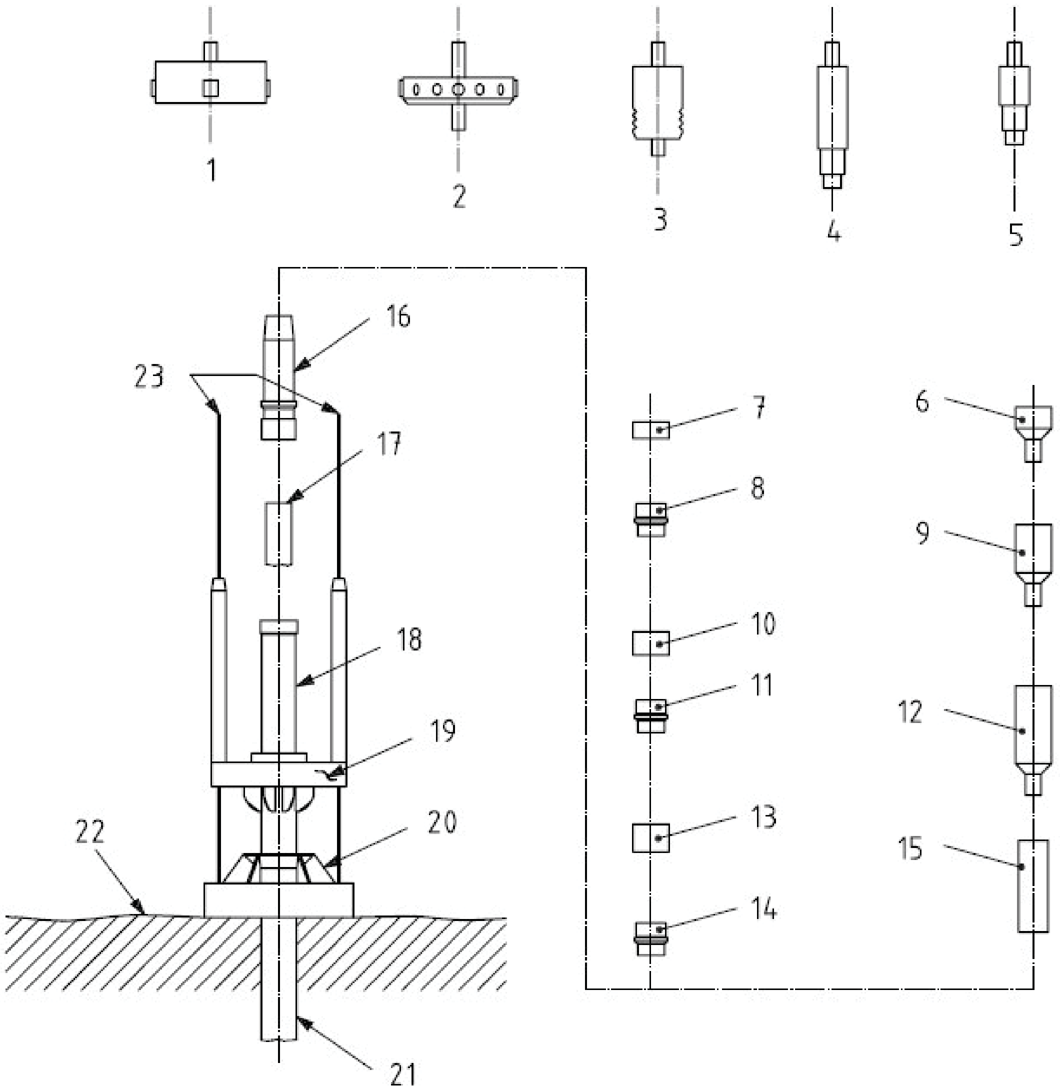
Other than in clusters, wells and manifold are situated on the same structure in a template configuration. Connections are therefore very short and are always made with rigid pipe. This allows for pre-fabrication and testing of equipment, hence reduced installation time. The template comprises of a foundation and a structural framework that provides support for seabed equipment. It may as well include protection against dropped objects and/or fishing gear. Just as in cluster configurations commonly two flowlines are used to tie back the manifold to a host facility. Larger templates tend to be tied back to a host facility individually whereas smaller ones (e.g. three to four wells each) are often daisy-chained together. [6, 14]

2.4.2 Subsea Wellhead Systems

The subsea wellhead (WH) is a pressure containing device at the seafloor that also acts as constructional anchor point for drilling and completion systems as well as for the casing strings. It contains internal profiles for casing string support and annuli isolation. Additionally it includes facilities for mechanical support, guidance and connection of drilling and completion systems (e.g. the blow-out preventer, production tree). [6, 14, 40]

Wellhead System Elements

Major components of a subsea WH system can be seen in Figure 8 and are being described further below.



Key

1 TGB running tool
2 762 mm (30 in) housing running tool
3 high-pressure housing running tool
4 casing hanger running tool (drillpipe or fullbore)
5 test tool
6 177,8 mm (7 in) wear bushing
7 244,5 mm × 177,8 mm (9 5/8 in × 7 in) annulus seal assembly
8 177,8 mm (7 in) casing hanger
9 244,5 mm (9 5/8 in) wear bushing
10 339,7 mm × 244,5 mm (13 3/8 in × 9 5/8 in) annulus seal assembly
11 244,5 mm (9 5/8 in) casing hanger
12 339,7 mm (13 3/8 in) wear bushing
13 508,0 mm × 339,7 mm (20 in × 13 3/8 in) annulus seal assembly
14 339,7 mm (13 3/8 in) casing hanger
15 housing bore protector
16 high-pressure wellhead housing
17 casing [normally 508,0 mm (20 in)]
18 low-pressure conductor housing [normally 762,0 mm (30 in)]
19 PGB
20 TGB
21 762,0 mm (30 in) conductor casing
22 sea floor
23 guidelines

Figure 8: Major components of a typical subsea wellhead system, from [6]

Guidance System [6, 14, 15]

The support base or guidebase serves multiple functions. It allows guidance of the subsea blow-out preventer (BOP) during drilling as well as the subsea tree assembly when completing the well. Guidance to the support base is usually accomplished by employing tensioned guidewires that run from the surface facility to the guide posts of the base. Additionally the guidebase supports the subsea BOP during the drilling phase as well as the set casing strings.

Depending on the SPS configuration (single satellite or template configuration) different types of guidance systems may be utilized:

A *temporary guidebase* (TGB, also: drilling guidebase) has an opening that allows for drilling of the first well section. It serves as a support for the permanent guidebase and provides a reference point for WH elevation. In case of single satellite wells the TGB may be left out whereas in templates it forms an integral part of the structures.

The *permanent guidebase* (PGB) or flow base sits on top of the TGB and is often installed in a way that the WH top is in a height (above the seafloor) that allows for drilling spoils and cement returns to be disposed on the seafloor without interference of guidance and support of subsea equipment.

On single satellite wells a *production guidebase* may replace the PGB after completion of the drilling process and prior to tree installation. The production guidebase includes facilities to connect flowlines, which allows for Christmas tree (XT) recovery without breaking the flowline connections. It may also be designed in a way that it serves as both the TGB and the PGB in once, thus eliminating the exchange procedure.

Conductor Housing [6, 41]

The low-pressure conductor housing is welded onto the conductor casing, the primary anchoring point on the seabed. It is of high importance that the conductor casing is placed correctly, since it provides the foundation for the whole well. The conductor housing holds an internal landing shoulder to host the wellhead housing as well as external facilities to fixate the PGB. It can be installed with the PGB or a production guidebase.

Wellhead Housing [6, 14, 41]

The high pressure wellhead housing acts as the primary pressure containing body in a subsea well. It holds an internal landing shoulder to support all casing strings subsequent to the conductor casing and external profiles to attach drilling and completion equipment (BOP, XT). Furthermore it contains a landing shoulder on the outside to mate with the conductor housing and transfer external loads to conductor housing and pipe, and eventually to the seafloor.

Casing Hangers [6, 41]

The casing hangers are suspending each single casing string in the WH housing. They stack on top of each other thereby transferring all casing weight from one hanger to another to the landing shoulder inside the WH housing. The casing hangers have annulus seal assemblies consisting of metal-to-metal seals with an elastomeric backup associated in order to ensure isolation of the existing annuli between the hanger and the WH housing. ISO 13628-1 recommends a lock-down mechanism for preventing casing hanger movement due to annulus pressure or thermal expansion during production. Such a mechanism would lock the annulus seal assembly to the WH housing. An illustration of casing hangers in a typical subsea WH system is given in Figure 9.

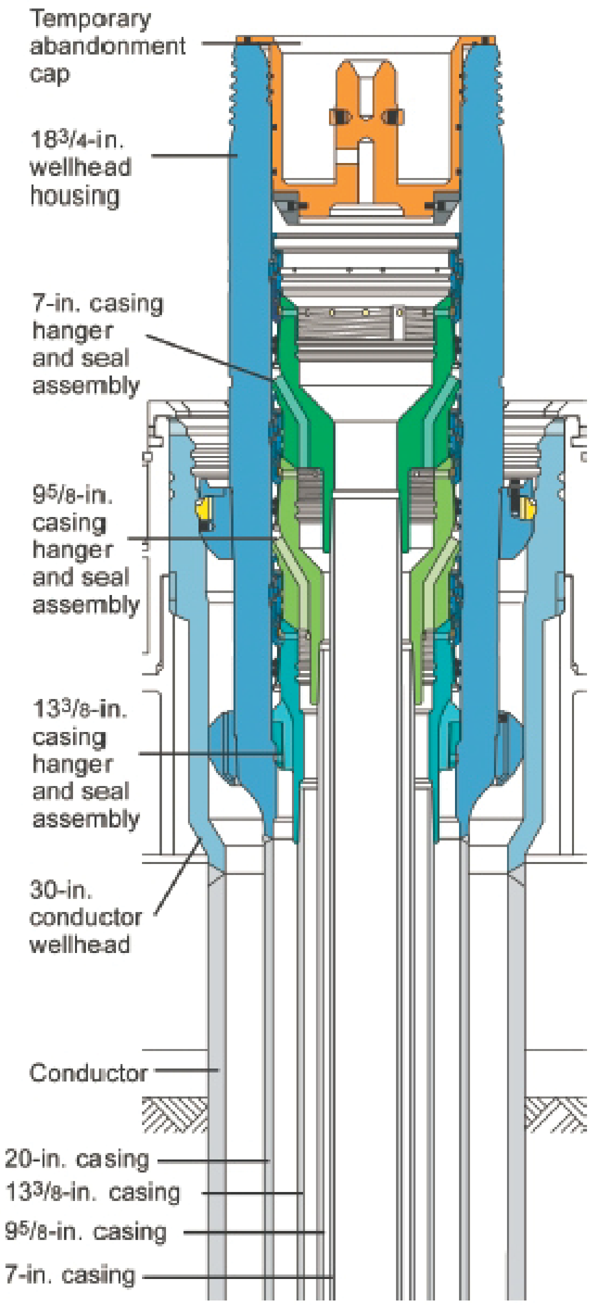


Figure 9: Illustration of a typical subsea wellhead system, from [41]

2.4.3 Subsea Tree Systems

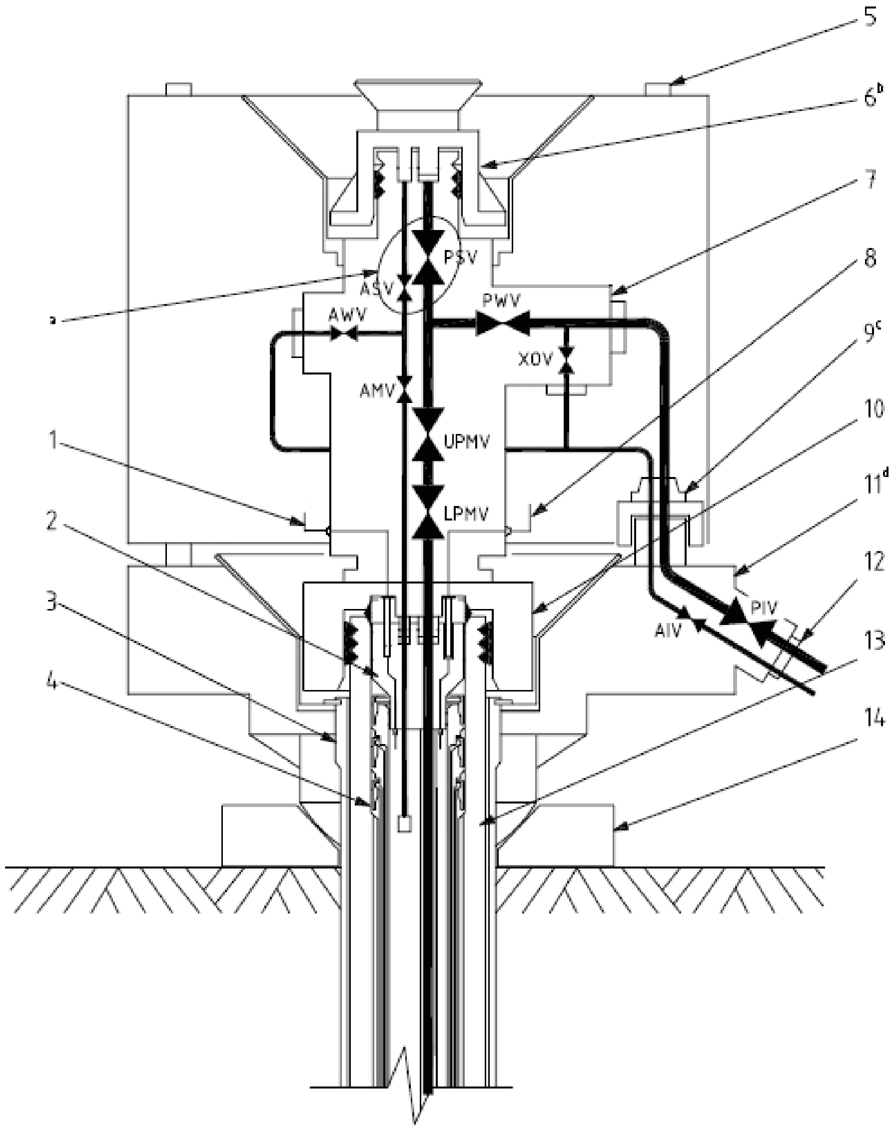
The combination of tubing hanger (TH) and XT forms the subsea tree system. In combination with the wellhead system they constitute the pressure barrier between reservoir and the environment during production and allow for control of the well. In a XT the TH seals off the annulus between tubing and production casing while supporting the tubing string in either the proceeding casing hanger or the XT. Another main function of the XT is the direction of fluids from the well to the flowline or vice versa. The functionality of a subsea XT is comparable to a surface tree, yet it is design for underwater operations and remote control. It hosts a series of valves that can be remotely operated to manage or interrupt fluid flow for operational and safety reasons. In multi-well developments (cluster or manifold configurations) the XTs are usually equipped with an actuated choke valve in order to being able to remotely control the relative flow from a single well. Generally it is differentiated between vertical tree (VXT) systems and horizontal tree (HXT) systems. [6, 14, 15, 40]

Vertical Tree Systems [6, 40]

A VXT has one or more production bores as well as one annulus bore running vertically through its body. The bores allow passing tools and plugs through the XT. Several gate valves (production valves) located on the vertical axis in the tree body permit isolation of the vertical bores at different levels. The vertical bores are intersected by two or more horizontal ones, thereby allowing fluid flow out of or into the well. All the horizontal bores are equipped with an insulation gate valve (wing valve) for shut-off of fluid flow. Communication between production and annulus bores is provided by the means of cross-over valves. Figure 10 shows a typical VXT including valves and conduits.

VXTs are designed for vertical access to production bore and annulus in case of installation and workover operations. This type of tree is normally installed inside the WH and has an interface with the TH, which has previously been installed in the WH, to form a pressure-sealing connection with the WH. Additionally bore extension subs running from the tree to the TH establish pressure-sealing conduits between main bore to the tree and annulus to the tree, respectively.

A tree cap offers prevention from marine growth in the upper tree connection area as well as the sealing bores. It may be pressure-containing, hence providing an additional sealing device. Control system components may as well be integrated in the tree cap.



Key

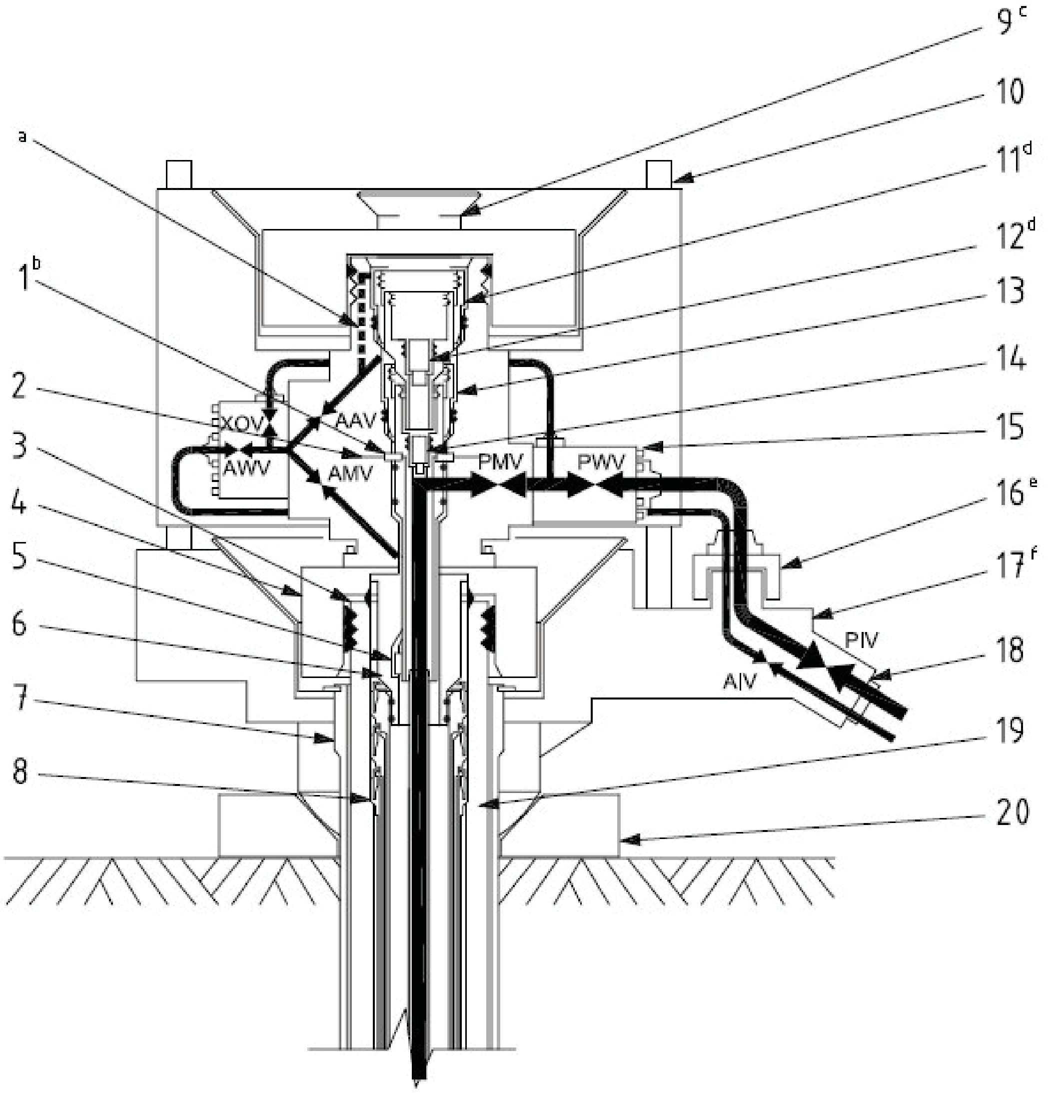
1 SCSSV control line
2 tubing hanger (TH)
3 conductor housing
4 casing hangers and seal assemblies
5 guideposts (optional)
6 XT cap
7 Xmas tree (XT)
8 DHPTT monitoring line
9 flowline connector
10 XT connector
11 guidebase
12 flowline/tie-in spool connector
13 wellhead
14 drilling guidebase or template slot

a PSV and ASV may be substituted with plugs.
b XT cap may be pressure-containing or non-pressure-containing.
c Flowline connection shown connected to Production guidebase, but may also be connected directly to XT.
d Production guidebase shown (allows connection of flowlines).

Figure 10: Vertical Christmas tree, from [6]

Horizontal Tree Systems [6, 40]

HXTs have horizontal branches of annulus and production bore to the outside of the tree body where the valves are situated. Deferring from a VXT, the HXT is installed on the WH first and then the TH is hung-off in the tree, instead of the WH. It is therefore possible to remove the tubing string from the well without having to recover the XT first. This makes this XT design relevant when utilising downhole equipment that requires retrieval at frequent intervals, such as submersible pumps, intelligent completions, etc. Furthermore the tree body is designed in a way that a BOP can be landed on top of the structure. No production or annulus swab valve is incorporated in a HXT. That makes the seal quality between TH and XT of very high importance. Figure 11 shows a typical typical HXT including valves and conduits.



Key

1	horizontal stroking couplers/connectors	11	internal tree cap (ITC)
2	SCSSV and DHPTT lines	12	ITC plug
3	wellhead	13	tubing hanger (TH)
4	XT connector	14	TH plug
5	TH orientation helix	15	Xmas tree (XT)
6	completion stab sleeve	16	flowline connector
7	conductor housing	17	guidebase
8	casing hangers and seal assemblies	18	flowline/tie-in spool connector
9	XT cap	19	wellhead
10	guideposts (optional)	20	drilling guidebase or template slot

[a] Permits annulus access without having to remove ITC.
[b] Hydraulic/CL lines may be made up with static seal mechanisms.
[c] XT cap may be pressure-containing or non-pressure-containing.
[d] ITC shown with plug. ITC may also be blind or fitted with ball valve.
[e] Flowline connection shown connected to Production guidebase, but may also be connected directly to XT.
[f] Production guidebase shown (allows connection of flowlines).

Figure 11: Horizontal Christmas tree, from [6]

Tubing Hanger [6, 40]
Similar to a casing hanger the TH supports the tubing string by forming a connection between the tubing and the XT. Additionally its purpose is to seal-off the annulus between tubing and casing. The TH is locked down within the XT. For a HXT, the TH normally is monobore. Annulus access is then provided by the means of side entry ports. The TH's vertical bore is normally sealed by a plug inside the XT and on top of the TH. An additional pressure-retaining barrier is provided by an internal tree cap inside the top of the XT. Furthermore a debris cap on top of the tree prevents marine growth inside the XT. Since statistically workover interventions are mostly owed to downhole issues rather than tree problems the HXT arrangement has proven advantageous in terms of reducing well intervention time and cost. Subsequently the need for a production guidebase is reduced since the tree is less likely to be retrieved. Therefore the production guidebase may as well be integrated with the XT to save a running operation. However, this comes at the expense of system flexibility, i.e. [6]:

- restricts installation of the flowline and umbilical until after the XT is installed;
- disturbs the flowline and umbilicals if the XT ever has to be recovered.

The VXT offers an advantage only, if the whole tree has to be recovered. This design allows for retrieval of the tree without interfering with the tubing.

Tree Valves [15]
The first valves above the TH are the *master valves*. One of these fail-safe closed gate valves is provided for each string penetrating the TH, i.e. one for production, one for annulus access, and one for any auxiliary line such as gas injection. Usually two master valves are deployed for the production string. During shutdown, the upper production master valve will be closed subsequent to the wing valve. The lower master valve is closed in emergency situations and during pressure testing only. This second production master valve adds reliability as well as valve testing opportunities but may as well be left out.
On the horizontal outlets of a XT, wing valves are situated. The *production wing valve* is the first valve on the XT to be closed in case of a production shut in. Using this valve as primary working valve when stopping the flow, allows for closure of the other tree valves as well as the downhole safety valves in a safe no-flow condition. To have no flow and no differential pressure across a valve during the closure reduces the risk for seat and gate erosion and deterioration to a minimum. To close the side outlet in the tree block an *annulus wing valve* is needed since it is necessary to isolate the service line for production and intervention.
In VXTs, *swab valves* seal the vertical bores while still permitting vertical access to the

wellbore. They are situated above the wing outlets and are only to be actuated via the workover control system, not the production control system. Swab valves may also be substituted by crown plugs which would need to be pulled in case of a workover operation.
Cross over valves enable connection between the annulus and the production flowline thereby allowing for circulation.
Isolation valves are situated at the flowline connector. These allow for isolation of the tree during connection and disconnection of the flowlines.
In case there is a *choke valve* on-board the XT it would be located downstream the production wing valve but it may as well be situated on a manifold instead. In any case the choke should be easily retrievable since it is subjected to high risk of erosion.
Utilised valves on XTs need to provide bi-directional sealing for safe use and to facilitate pressure tests. Tree valves have to be closed (and opened) in sequence to avoid hydraulic pressure lock between valves. Additionally to the tree valves there are others located on a subsea manifold and the surface facility.

2.4.4 Subsea Processing Systems

One of the challenges in SPS is "how to reduce wellhead pressure to allow effective recovery of hydrocarbon resources" [42]. If the offshore host facility lacks space and/or payload capacity or in the absence of an offshore facility at all (if the SPS is tied-back to shore), this issue can be addressed using subsea processing [43]. The term subsea processing (SSP) is defined as "any handling and treatment of the produced fluids for mitigation of flow assurance issues" [14] before they reach a host facility. This basically includes all separation and pressure-boosting operations performed subsea, regardless of whether they are carried out downhole or on the seabed. [6]
Primary technologies utilised are [6]:

- separation (two-phase and three-phase),
- pressure-boosting (multi-phase pumping and gas compression),
- water disposal (may be linked to re-injection).

Normally, wellhead pressure is drawn down to about 100 to 200 psig at the end of a field's life. For subsea wells with long tie-back distances, the abandonment pressure may be well higher (1,000 to 2,000 psig) due to the additional backpressure owed to the long flowline. Ultimate recovery is further reduced by this constant backpressure throughout the life of the field [42]. If the backpressure on the reservoir is reduced, recoverable reserves as well as production rates are increased and the field can be abandoned at a lower pressure level, leading to higher ultimate recovery. A SSP has

the benefit of enabling (improved) recovery of hydrocarbons as well as long tie-back distances. It may as well be beneficial for total CAPEX as it could reduce topside processing and/or flowline CAPEX and additionally provide advantages in terms of safety and environmental concerns [44].
Besides costs, the main considerations influencing the SSP system design are technology and location of the processing facilities. All aspects need to be evaluated on a through-life basis since e.g. fluid properties may vary throughout the lifetime of a field and processing for boosting the production is often needed in a later stage of a field development. The SSP equipment shall in most cases be placed as close to the reservoir as possible for considerations regarding fluid properties as well as thermodynamic and mechanical efficiencies. Opposing that, engineering factors and maintenance requirements ask for the SSP equipment to be placed as far downstream as possible. Balancing these two conflicting requirements is the key to an optimum field development solution from both an economic as well as a technical point of view. [6]

Separation & Water Disposal [6]

There are various reasons for carrying out separation subsea. Water can be separated much closer to the reservoir as it would be possible at a topside facility, thus reducing backpressure on the system. That also reduces the amount of fluids that need to be transported and minimises the requirement for water-handling topside since the water can be re-injected or disposed subsea, provided it meets the requirements. Additionally water injection may assist to maintain reservoir pressure.
Gas-liquid separation enables single-phase boosting methods which are more efficient than multi-phase ones. Due to a reduced back-pressure on the reservoir recoverable reserves as well as production rates are increased and the field can be abandoned at a lower pressure level. Therefore, gravity separation systems as well as cyclonic separation systems are used. Furthermore, flow assurance problems that occur during multi-phase transport of well fluids can be eliminated. These include corrosion and hydrate formation and may reduce the need for chemical injection. Great attention shall be given to solids management which is a significant issue in a SSP system. Downhole sand-control as well as monitoring of sand production should be considered.

Pressure-Boosting

Multi-phase pumps add energy to the system thereby boosting the production above natural flow conditions, and in this way making up for parts of the pressure loss along the production system. Potential benefits include increased recovery and better outflow performance, as well as long-distance tie-backs. [6]
Figure 12 illustrates the change in node characteristics due to the use of a multi-phase pump.

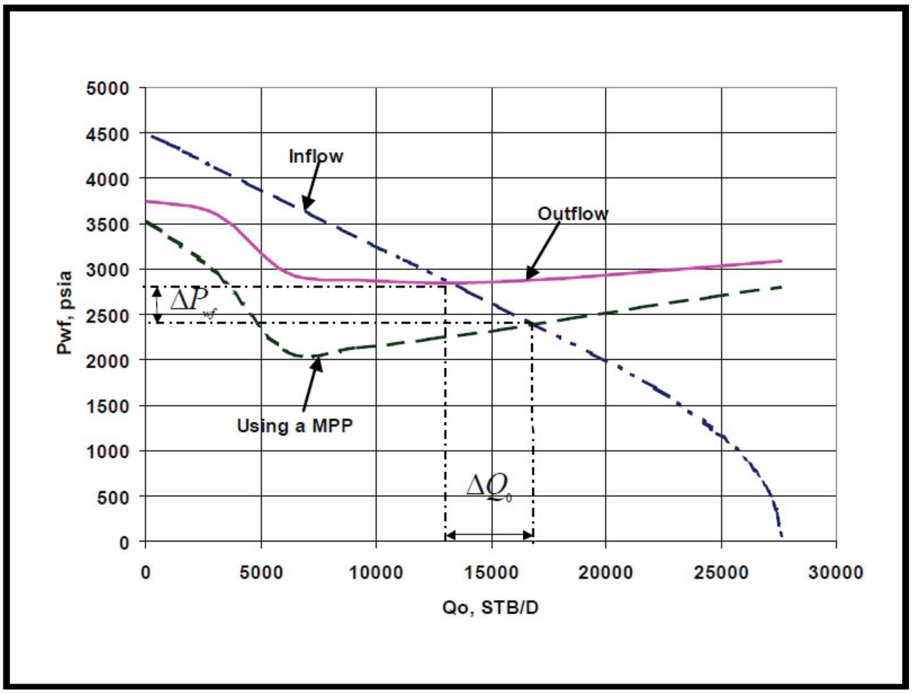


Figure 12: Nodal analysis plot showing increased production rate and decreased wellbore flowing pressure as the effects of using a multi-phase pump, from [42]

Submersible Pumps [6]

Downhole pumping is preferred from a system efficiency perspective and both hydraulic subsea pumps and downhole electric submersible pumps (ESPs) have been deployed subsea. Yet, factors like the need to provide one pump per well or the impact of the pump on the casing size and the subsea tree design, as well as reliability and maintenance concerns may favour a different solution.

Seabed multi-phase pumps [6]

Generally two types of multi-phase pumps are utilised subsea: hydrodynamic pumps and positive displacement pumps. In developments with shorter tie-back distances, placing the pump close to the riser base should be considered if possible to facilitate repair and maintenance operations.

Wet-gas Compression [6]

Designed for the same basic service as multi-phase pumps, wet gas compressors are meant to handle high gas volume fractions, usually between 95 to 100%. CAPEX savings may come from the resulting need for flowlines of smaller diameter between the SSP and the host facility. Such a system was deployed in 2015 at the Gullfaks field on the NCS.

Dry-gas Compression [43]

SSP system containing a dry-gas compressor will be deployed in fields with larger volumes or ones that need a larger pressure boost due to longer tie-back distances. Such systems are more sophisticated than the ones with a wet-gas gas compressor as they require gas scrubbing upstream the compressor. The first subsea dry-gas compressor was deployed by Statoil in 2015 at the Åsgard field on the NCS.

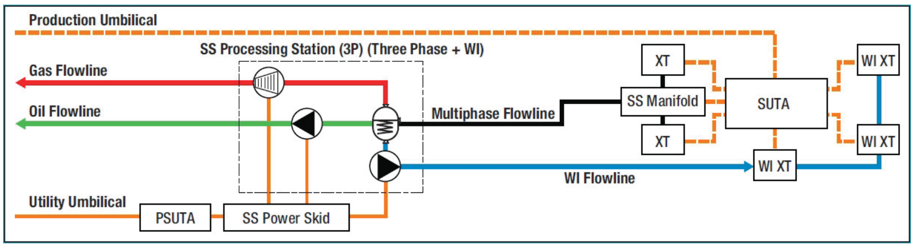


Figure 13: Process flow-diagram for a long distance tie-back field development example, incorporating a SSP system, from [45]

Figure 13 shows an example of a field development layout as it is likely to be used in a long-distance tie-back situation. It incorporates a subsea processing station including a three-phase separator, pumps for oil and water phase as well as a gas compressor. The separated water is re-injected into the reservoir. Umbilicals provide electrical and hydraulic power that is distributed by subsea umbilical termination assemblies (SUTAs).

Monitoring [6]
SSP require the monitoring/measurement of additional process variables to the conventional pressure-and temperature-monitoring. On top of that it is desired to monitor SSP equipment condition directly. Reliability and wear trends, respectively, can thereby be determined and performance optimized.

2.4.5 Production Control Systems

Early subsea completions needed to be controlled manually by divers. Nowadays production control systems (PCSs) allow to remotely control and monitor a SPS during its operation. They involve equipment subsea (i.e. electronic module, actuators, position indicators) as well as topside (i.e. electric and hydraulic power unit, control unit) that is connected through an umbilical. The high number of components and interfaces involved makes these systems quite complex. It is essential to recognize this aspect in order to ensure smooth installation and commissioning as well as long-term reliability. [14, 46, 47]
Available systems are classified as direct hydraulic, discrete piloted hydraulic, sequential piloted hydraulic, direct electro-hydraulic and multiplexed electro-hydraulic (MUX E/H). All of the named systems need to supply high-pressure hydraulic fluid to subsea located control devices. This is being achieved by a hydraulic power unit (HPU), and an accumulator unit that stores hydraulic pressure. Both are situated either topside or

subsea. [6]
MUX E/H systems are most commonly employed today. Compared to other classified systems these offer a high level of functionality in combination with fast response rates. PCSs are primarily used for safe and reliable opening and closing of subsea valves including shut-in production. Main valve types include ball valves, choke valves, gate valves and downhole safety valves [46]. Additionally MUX E/H systems may also be used for controlling the position of chokes as well as for monitoring of subsea parameters and system variables and transmitting this data to the host facility as they provide the means to monitor a high number of parameters as an integral part of the system. The therefore needed communications cable may be substituted by superimposition of control signals on the power lines or a fibre optic cable. [6]

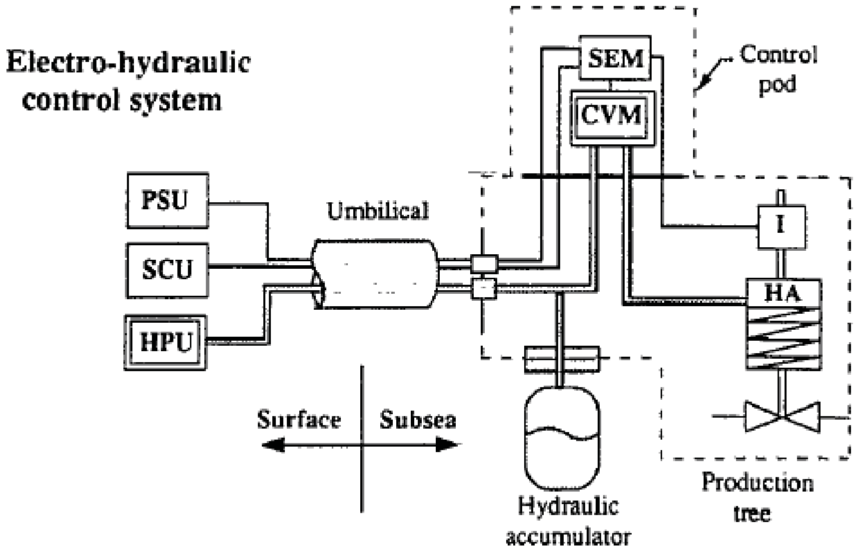


Figure 14: Typical electro-hydraulic control system, from [46]

MUX E/H systems comprise of surface as well as subsea components as can be seen in Figure 14. Additional to the already mentioned HPU the system includes an electrical power supply unit (PSU) and a surface control unit (SCU, synonymous for master control station) topside. The subsea control module (SCM, in Figure 14 referred to as control pod) includes a subsea electronic module (SEM), communications system and a control valve module (CVM). In this module commonly solenoid valves are utilised which allow stored hydraulic pressure from the HPU and the accumulator, respectively, to be routed to hydraulic actuators (HA) situated on the individual tree valves. The SEM also collects data from its interfaces to sensor like position indicators (I). [46, 47]
On the downside, MUX E/H systems include a higher number of system components both topside and subsea compared to the other systems classified. Just as in any hydraulic system pressure support as well as fluid cleanliness may be an issue. Additionally, from a HSE point of view, possible leakage of hydraulic fluids is of environmental

concern. [6, 46, 47]
The latest developments in PCSs concern all-electric systems. These systems evolved as a response to the limited practicality of MUX E/H systems in deepwater and long step-out field developments. All-electric systems significantly reduce the amount of components involved in the system as can be seen in Figure 15. Instead of hydraulic power electric power is used for the operation of valves, thus hydraulic parts are removed completely from the system which results in increased system reliability. This allows for the usage of rather simple electric cables instead of more complex multicore electro-hydraulic umbilicals. [46, 47]

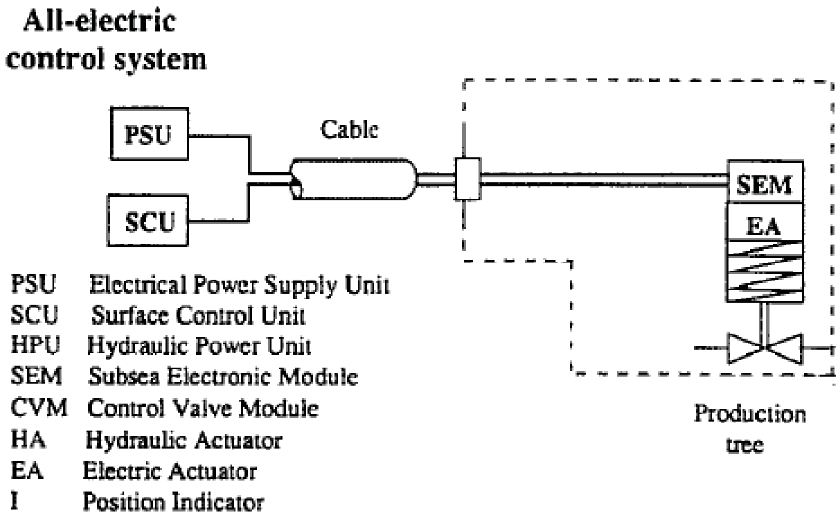


Figure 15: All-electric control system, from [46]

When it comes to monitoring and data transmission to surface, fibre optics offer an alternative. Fibre optic sensors are small in size and are designed for high temperature and high pressure application. They do not require electrical power and offer a wide spectrum of applications, such as temperature, pressure, acoustic and seismic measurements. These sensors share a common infrastructure and can easily be replaced. Data transfer is managed by means of fibre optic cables. These are immune to electromagnetic interference and cross-talk and have a lower mass compared to copper cables. Fibre optic cables also permit sensing in remote locations since transmission losses at high frequencies are lower than in coaxial cables, hence less repeater stations are needed over long distances. Furthermore electric sparking and fire hazards are eliminated. [6, 48]

2.4.6 Flowlines and Umbilicals

For flowline and umbilical components ISO 13628-1 [6] distinguishes between ”lines that convey fluids”, such as pressure containing lines, and “lines that do not convey fluids”, such as electrical and fibre optic cables. These components comprise the line itself as well as some kind of connection at either end to allow for connection of the component with another subsea or surface equipment in order to perform its intended function. Spools or jumpers may assist these connections. [6]

Pressure Containing Lines [6]

Pressure containing lines include flowlines for reservoir fluids (pre- and post-separation), injection lines, service lines (i.e. for chemical injection, gas lift, monitoring, well killing, etc.) as well as hydraulic lines for actuated devices. They may be manufactured of rigid or flexible pipe. Small-bore lines, i.e. hydraulic, monitoring, or chemical injection lines, may as well be manufactured of thermoplastic hose. There are different connection techniques available, however the main purpose of the connector, which is to provide a pressure-tight seal that withstands subsea environments, remains unchanged.

Electrical and Fibre Optic Cables [6]

In a SPS, electrical power may be needed for an electro-hydraulic PCS and/or for SSP equipment, i.e. a multiphase pump. Separate power cables are required for these two applications because of the differing power demands. Additionally, electrical cables may also be utilised when inductive heating of flowlines is used to prevent or remediate flow-assurance issues, like wax and hydrate formation. Electric or alternatively fibre optic cables are needed in an electro-hydraulic PCS for transmitting control signals as well as data between the subsea and the host facility. Instead, signals may also be superimposed on the power output (“signal on power”).

Flowlines and or umbilicals may be strapped together to a bundle in small numbers. These can even include fluid circulation lines form warm fluids in order to assist with flow-assurance issues. However, bundles have somewhat limited advantages as every line should at least be partially designed for independent application.

Two or more lines with often different functions can be combined to a multicore umbilical (MCU). MCUs are normally armoured with steel wire while still flexible enough to be deployed using a reel on an installation vessel. Its subsea end is usually connected with the subsea umbilical termination or SUTA, respectively. Such a device incorporates connectors for all lines involved and may also include valves for isolation purposes. The SUTA is either directly connected with a manifold or subsea XT or to a subsea umbilical distribution unit that has multiple connection points suitable for a multiwell development.

2.4.7 Risers

Risers are the part of a pipeline that runs from the seafloor to the surface. They provide a conduit for the purpose of transporting fluids therebetween. When these are produced and/or injection fluids such risers are referred to as production riser. In general, production risers that are tied back to fixed structures are less complex that the ones tied-back to floating facilities. This is due to the need for absorbing the motion in case of floating structures. [6]

2.5 Health, Safety and Environment

Safe, reliable and efficient operations are a common goal in all activities of the oil and gas industry [49]. Therefore concerns regarding HSE are of high relevance. Within exploration and production (E&P) companies these three separate disciplines are often combined in one functional group. The individual functions consider the well-being of employees (health), protection of employees by minimising risks from operational hazards (safety) and the effects on the external environment, such as the ones of emissions and waste disposal or waste water discharge. HSE programs of SPSs also include the assessment of environmental and socio-economic impact which has to be completed prior to project sanction. This applies not only for construction and operation but also for the removal of subsea equipment. [50, 51, 52]

HSE performance is one of the prime measures in offshore operations and is aimed to be maximised [53]. Due to the transfer of more and more facilities subsea, risks regarding health and safety of personnel are actually reduced during normal operation. One of the main benefits in applying SSP regards HSE, due to “reduced fire and explosion risks, chemical consumption, manned offshore operations environmental footprint and improved energy efficiency.” [43]. Processing systems located on host facilities usually have greater HSE challenges than SSP installations [25]. All-electric subsea PCSs, as discussed in Chapter 2.4.5, can also increase the environmental performance as they eliminate hydraulic fluids; hence these cannot accidentally leak to the environment any longer. At the same time personnel safety is improved since fluid handling and contamination risks are eliminated. [47].

Methods like riser-less well intervention (a procedure that allows for optimised utilisation of vessels and rigs) ensure improved HSE performance also during subsea well interventions. The risk of fire and explosions onboard the intervention vessel is reduced significantly by this method. Furthermore, there is only limited need for the topside use of pressurised equipment and pipe handling is removed. [54]

Another important aspect related to HSE performance is maintenance, which will be discussed in chapter 3.

2.6 Alternative Solutions

Dry Tree Systems [14, 55]

As an alternative to wet tree subsea systems, which have been described in the previous sections, dry tree systems may be considered. Such systems have the wellhead above the water surface on an offshore facility. Top-tensioned production risers enable the tie-back of the subsea wells to such an installation. A well bay area in the centre of the facility hosts the risers. Flexible jumpers are used between the riser and the host to make up for any relative movement. Figure 16 shows the layout of a dry tree system realised on a TLP.

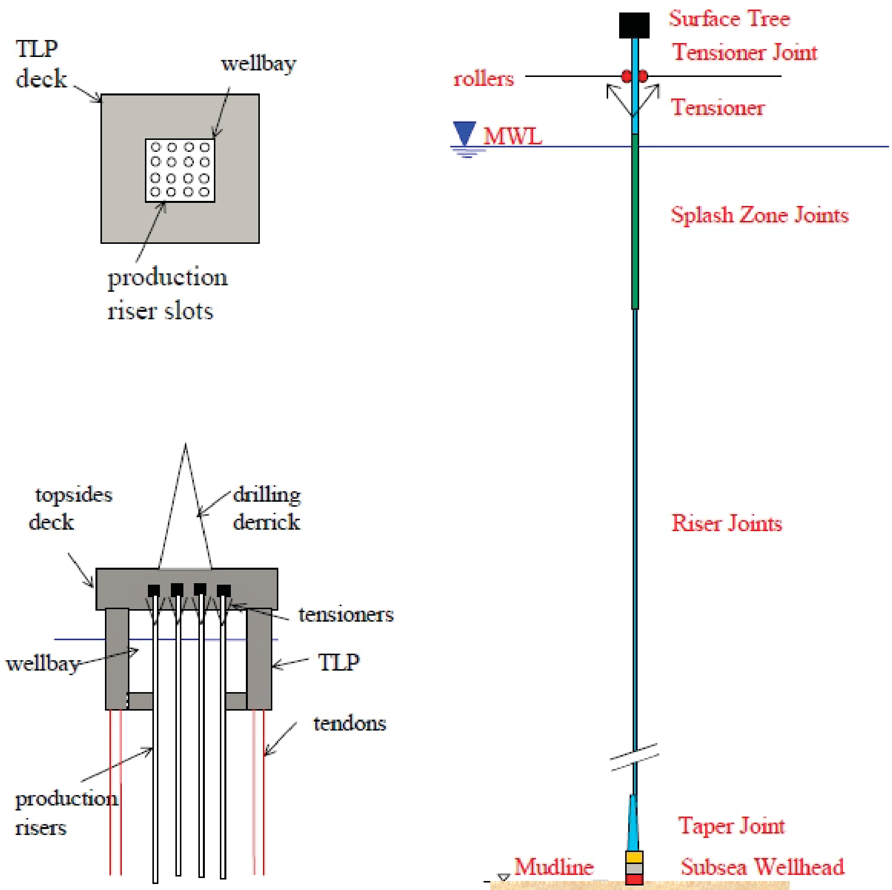


Figure 16: Plan and elevation views of TLP and TLP riser arrangement, from [55]

Since the host facility is placed in a in a straight line above the well, direct access to the wells is guaranteed and no specialised vessels for drilling or workover activities are needed.

As mentioned earlier, there may be limitations on topside facilities regarding load and space. Additionally, processing on the surface is usually less efficient and dry tree systems are limited in connection with water depth and development flexibility. They are therefore widely used in shallow to medium water depths but not deemed optimum for developments in deeper waters.

Minimum Facility Platform [56]

A special application of dry-tree systems is the one on a minimum facility platform (MFP). A MFP, or unmanned wellhead platform, has a fixed substructure deployed on the seabed. Typically, a MFP does not host extensive separation or processing facilities but dry-trees and manifolds only. Therefore, produced fluids are transported multi-phased from the MFP to a processing facility. In Figure 17 an example of a MFP embedded in a marginal field development is given.

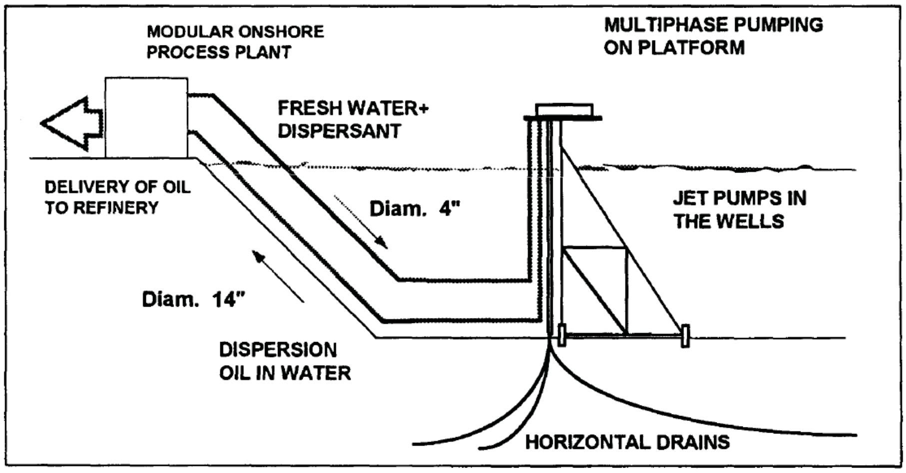


Figure 17: Example of an offshore marginal field development layout including a MFP, from [57]

One of the advantages of a MFP over other fixed production facilities is that less CAPEX is associated with its deployment. This makes it a valuable option for marginal field developments, satellite fields or infrastructure expansion in shallow waters.

Chapter 3

Maintenance of Subsea Production Systems

In IMR activities for SPSs special tools and equipment as well as specially trained personnel are needed which makes them very expensive. Additionally, vessel specifications and availability, mobilisation time, season and weather conditions, water depth, stockage of spare parts, and possible obsolescence of components need to be considered. [4]
In offshore operations production availability as well as HSE performance are prime measures and it is worthwhile to maximise both at the same time [53]. This indicates the importance of maintenance strategies, especially for SPSs when taking into consideration the challenges named above. There are four objectives an operator's maintenance program has to address [58]:

- To ensure realisation of the inherent safety and reliability levels of the equipment
- To restore safety and reliability to their inherent levels when deterioration has occurred
- To obtain the information necessary for design improvement of those items whose inherent reliability proves inadequate
- To accomplish these goals at a minimum total cost, including maintenance costs and the costs of residual failures

Issues regarding HSE are equally important. These concerns can be added to the objectives above as they are to be addressed in the same way. If production availability is included as well objectives for an offshore operations maintenance program read as follows [53]:

- To ensure realisation of the inherent HSE and operation-availability levels of the equipment

- To restore HSE performance and operational availability to their inherent levels when deterioration has occurred
- To obtain the information necessary for design improvement of those items whose inherent HSE performance and operational availability proves inadequate
- To accomplish these goals at a minimum total cost, including maintenance costs and the costs of residual failures

Deployment/installation, operation and maintenance of SPSs are demanding in several ways. The remote location, harsh weather conditions, the need for specialised personnel and equipment, availability of vessels and the increasing system complexity need to be taken into consideration. Intervention therefore shall be thoroughly planned and executed precisely. This will ensure minimum down-time, hence minor production loss as well as improved overall system reliability and increased HSE performance. It therefore shall be analysed what kind of maintenance strategies are available and furthermore applicable to SPSs and how these approaches contribute to the named aims.

3.1 Maintenance Strategies

Preferably, maintenance aspects should already be considered from the early concept phase when designing a system. At that stage it is still possible to make significant changes to the system if needed. Moreover, maintenance strategies should already be in place before system commissioning rather than serving as a workaround as problems occur. [59]

3.1.1 Overview of Maintenance Strategies

Maintenance strategies can be classified as planned and unplanned in the widest sense. Since catastrophic failures cannot be predicted, this type of (unexpected) failure always requires unplanned corrective maintenance, no matter what kind of maintenance strategy is implemented. [4, 60]
Besides that, several approaches are available for planned maintenance. A “Journey to Operational Excellence” that displays performance measures in relation to the level of maintenance was first suggested by Dunn [61] and subsequently used and extended by Skytte af Sätra et al. [53] and Boschee [62]. Their approaches are combined in Figure 18. On the far left side of the figure you could consider maintenance at a very immature level. In a stepwise development more sophisticated strategies were introduced over time. The further the level is moved to the right, the closer it gets to excellence [61].

Evolving along the path can therefore be seen as roadmap to operational excellence [53]. Moving from one maintenance category to a more mature one as an organisation requires from 12 to 18 months [62]. Data acquisition and processing have increased parallel to the maturation of maintenance programs [53].
In order to be effective, a preventive maintenance (PM) task has to supply a reduction in expected loss relevant to "personnel, injuries, environmental damage, production loss, and/or material damage." [59]

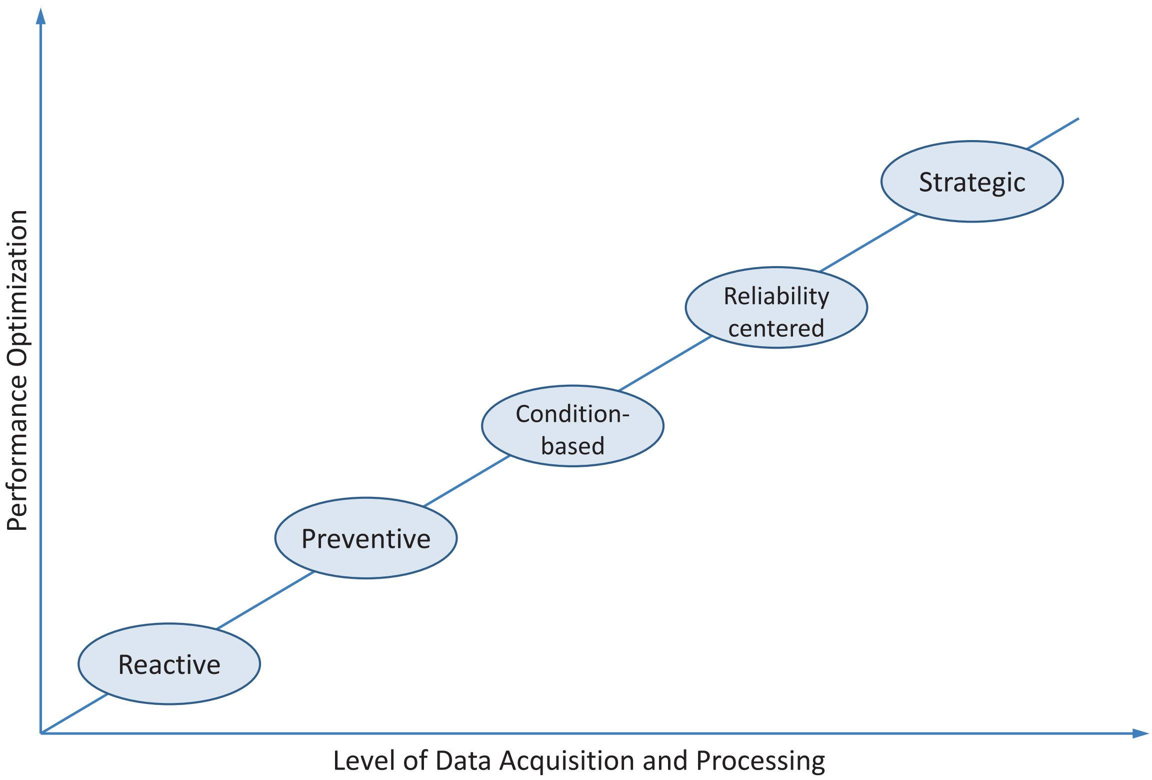


Figure 18: Types of Maintenance Strategies, modified from [53, 61, 62]

Terminology regarding maintenance is sometimes confusing or overlapping, e.g. proactive maintenance is also a form of PM or strategic maintenance still involves PM. Therefore an effort is made to clarify terminology and stick to these expressions throughout the entire work. In the following paragraphs a brief introduction to the different strategies shown in Figure 18 is given.

Reactive Maintenance

In case a component fails, some remediate action is performed (unplanned corrective maintenance). This action can be carried out immediately after the failure has occurred or postponed to a later point in time if the overall system condition allows for it. Immediate interventions often come at high expenses making it necessary to plan the actual maintenance and modification activities ahead of time [4]. There are no efforts taken to predict the components condition or estimate the remaining useful lifetime (RUL).

Preventive Maintenance

Maintenance is carried out at planned and predefined periodic intervals. The specific time of the intervention can thereby be determined based on usage or calendar time, manufacturer recommendations, or worker experience [63]. All subsequent maintenance approaches can still be seen as preventive, but they incorporate certain additional features.
Although not highlighted specifically by [53, 61, 62] risk-based inspection (RBI) is a special form of PM that is often named in relating to offshore facilities. The aim of this concept is to prioritise and optimise inspection by balancing the benefits of risk reduction against inspection costs. RBI considers criticality and failure modes of equipment to develop an inspection and maintenance plan for every item. The objectives of RBI are to reveal major failure types and to work out a plan for mitigation and control of these failures in order to maximise availability and reliability as well as to ensure system integrity. The RBI system is multidisciplinary as it considers threats and opportunities of technical, financial, commercial, and political risks. In a continuous process the most recent system information is gathered from inspection results, analysed in central register and subsequently fed back into the planning process. The analysis can be done as follows. In a qualitative approach, risk is assessed via descriptive data based on engineering judgement and experience. For a quantitative approach probabilistic or statistical models are used. A Semi-Quantitative approach unites elements of both the qualitative and the quantitative method.
The resulting inspection plan from an RBI assessment clearly states when, where, and how to inspect and also what degradation modes to inspect for. This shall eliminate unplanned failures, improve system performance and reduce costs. [14, 64, 65]

Condition-based Maintenance

This maintenance strategy is based on monitoring of the condition of equipment to successfully identify the most cost-effective frequency of maintenance actions. The main idea is to avoid failures by being able to intervene before defects actually occur. Therefore a model that forecasts future component behaviour is implemented. Traditional approaches use distributions of event records of identical components, prognostic approaches involve CM whereas other approaches integrate both failure predictions as

well as condition data. [53, 66]
Condition-based Maintenance (CBM) is sometimes given the deprecated term predictive maintenance [67].

Reliability Centred Maintenance

ISO 13372 [67] defines Reliability Centred Maintenance (RCM) as "disciplined logic used to identify those cost effective and technologically feasible maintenance tasks that realise the inherent reliability of equipment at a minimum expenditure of resources over the life of the equipment". In other words RCM is used to determine the most cost-effective preventive maintenance program that will ensure inherent equipment reliability is realised. Sometimes also referred to as "proactive" maintenance, it involves the monitoring of root causes [53]. Unlike the approaches introduced previously, this strategy focuses on functionality of the overall system rather than on single components only. Reducing the cost of maintenance "by focusing on the most important functions of the system and avoiding or removing maintenance actions that are not strictly necessary" [59] is the main objective of RCM. Therefore functional requirements and failures as well as their consequences are analysed in detail. The knowledge is built by cooperation of several disciplines within the organisation. [59]

Strategic Maintenance

This approach can be seen as enterprise effort. Additionally to the principles of RCM it also considers aspects of Integrated Operations (IO) and/or enterprise asset management. IO is thereby a concept that allows people, technology and work processes to be combined and to collaborate across distances, disciplines and companies. It was defined as "real-time data onshore from offshore fields and new integrated work processes." [53] and improves availability, hence production rates, and has a positive impact on HSE aspects. Skytte af Sätra et al. [53] identified IO as well as a holistic CM system that performs real-time diagnoses and offers decision support as factors to successfully reduce operational expenditure (OPEX). Enterprise asset management embraces the strategy to reach reliability and maintenance goals, maintenance-, repair- and operation-processes, enabling technologies and engineering data. It shall lead to reduced maintenance cost and increased asset longevity as well as improved uptime and management of risk and safety factors. [62, 53]
Factual Maintenance [68] also adds an additional feature to RCM. The cross-plant maintenance approach, that is applicable for multiple plants with the same basic design, shall reduce risk by including operator knowledge into the maintenance strategy. A platform is established in order to ensure proper cross-plant communication of best

practises and lessons-learnt. This could give an objective basis for the decision for a maintenance plan.

For the sake of completeness it shall also be mentioned that there is the approach to not fix a component in case of failure [61]. This can be seen as the most immature category of maintenance of all as well as an initial starting point when introducing maintenance strategies. However, since it does not involve any actual maintenance action, process or technology it is not considered in this overview.
According to Boschee [62] about 90% of organisations in the oil and gas sector place their maintenance efforts regarding equipment, facilities, and processes in the “preventive” category. This is also the category offshore and subsea activities lie in, which are additionally said to be more advanced in using CBM.

3.1.2 Maintenance Strategy Selection

There are several approaches on how to address reliability issues. Which method actually will be chosen is highly depending on economic considerations. The decision to repair a component is typically based on a cost/benefit evaluation [53]. The main question thereby is if differed production outweighs intervention cost [69]. This ultimately points to the fact that strategies deemed proper for some components may not be suitable for others. A detailed analysis is needed to identify costs as well as consequences of component failures.
ISO 17359 [70] offers a procedure for how to implement a CM programme, see Figure 19. It suggests starting with a return on investment (ROI) analysis. A method to assess the impact of varying intervention strategies was presented by Eriksen et al. [69]. It evaluates the balance between intervention cost and deferred production. Subsequently an equipment audit shall be performed to identify components and processes as well as their functions. It is essential to clearly identify all equipment including associated supply, control, and surveillance systems. For evaluation of equipment functions it is not only important to name the duties of the item in question but also to describe its designated operating conditions. In the next step reliability and criticality are assessed. This gives a prioritised list of items to be included in the CM programme. Additionally the performance of failure mode effect and criticality analysis (FMECA) is recommended “in order to identify faults, symptoms, and potential parameters to be measured which indicate the presence or occurrence of faults.” [70]. This audit gives information on the parameters that need to be measured for certain failure modes, which generally are the ones that indicate a fault. The selection of the appropriate maintenance strategy is then based on the question: is the fault measurable? Depending on the outcome, this may lead to the use of CM (in case the answer is “yes”) or an

alternative maintenance strategy. This may be the use of corrective (reactive) or preventive maintenance, the approach of run to failure or even the re-design (modification) of the component, system or process.
A similar analysis for RCM has been presented by Rausand [59].

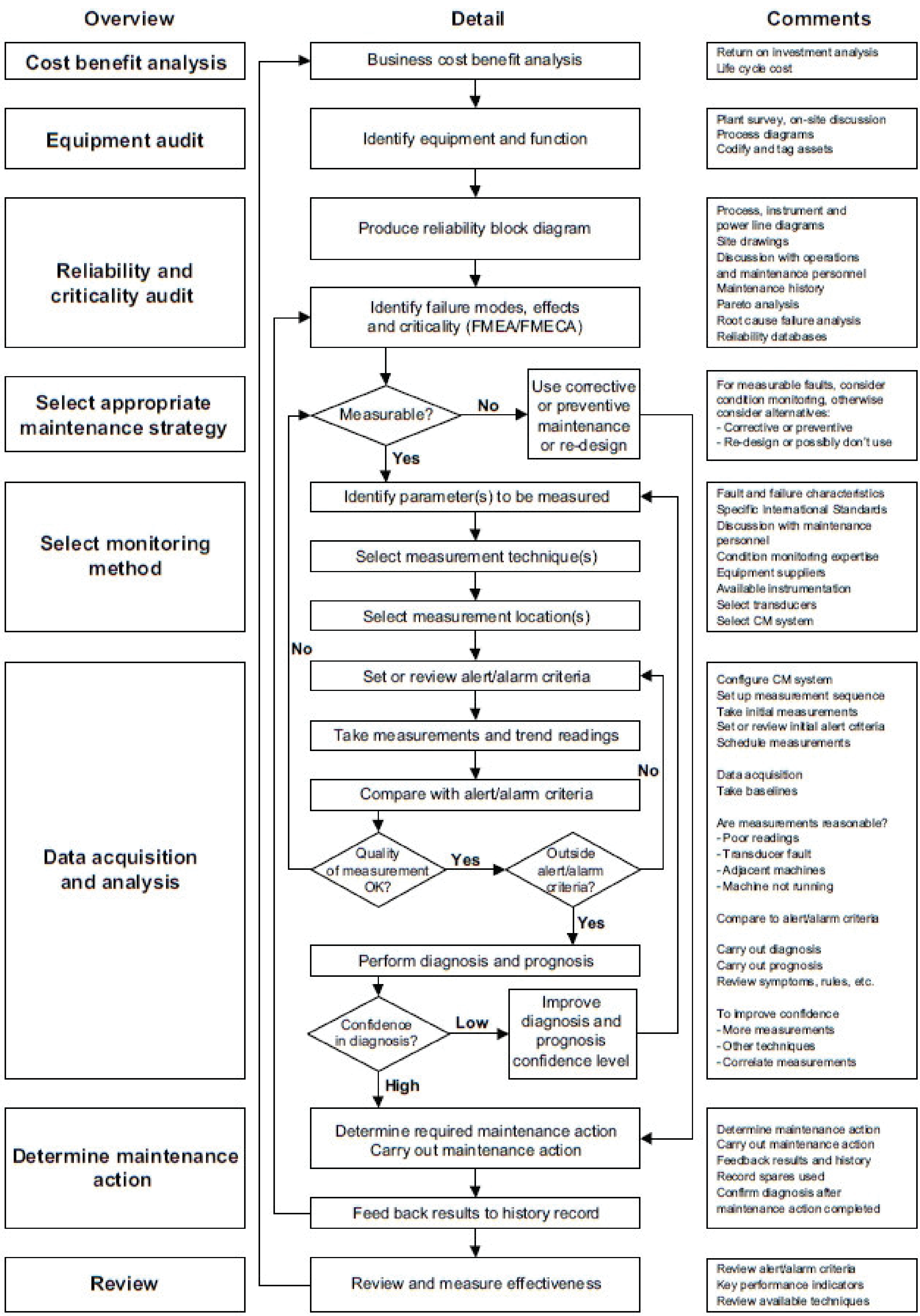


Figure 19: Condition Monitoring procedure flowchart, from [70]

3.2 Known Issues in Subsea Production Systems

It has been outlined previously that for PM it is helpful if not substantial to know about possible failure modes of the equipment to be maintained in order to apply proper actions. At this point it shall be clarified that there is a fundamental difference between a failure mode and a failure mechanism. A process (physical, chemical or other) that deteriorates an item and results in a failure is called a failure mechanism. A failure mode however is defined as the “observable manifestation of a system fault”. [67]
Typically affected components in SPSs are choke valves, cables, flanges or fasteners as well as PCSs. Choke valves may suffer from erosion due to sand production. For cables, electrical insulation needs to be maintained in the saltwater conditions it is operated in since losing insulation will result in electrical short circuit. Failures in flanges or fasteners may be caused by corrosion, overload or fatigue. Hydraulic components involved in PCSs such as valves can be affected by frequent operation and may leak. [63, 71, 72]
To effectively analyse risk of hazards to people and environment, or system performance equipment reliability and maintenance data is vital. Therefore, [73] “a clear understanding of the equipment technical characteristics, its operating and environmental conditions, its potential failures and its maintenance activities” is required. Furthermore, the failure causes need to be clarified in order to prioritise and implement corrective actions resulting in improved reliability, thus profitability and safety.
ISO 14224 [73] offers a basis to collect reliability and maintenance data in a standard format. It defines main equipment categories which comprise of several equipment-classes as well as failure modes. Such a standardised approach for data-collection allows for simple data-exchange between relevant parties, such as owners, contractors and manufacturers. Additionally the standard provides support for failure interpretation as well as notations for failure and maintenance data, i.e. failure mechanisms, failure causes, detection methods, maintenance activity and failure modes. Regarding failure modes, the standard recommends to record them on lower levels than the equipment-class for subsea equipment, e.g. at the “maintainable-item” level”. Furthermore it categorises failure modes into three types [73]:

- desired function is not obtained (e.g. failure to start);
- specified function lost or outside accepted operational limits (e.g. spurious stop, high output);
- failure indication is observed but there is no immediate and critical impact on the equipment-unit function [these are typically non-critical failures related to some degradation or incipient fault condition (e.g. initial war)].

For main equipment categories, e.g. subsea equipment, failure modes are presented. Equipment-classes for subsea equipment are subsea control system, Christmas trees, subsea pumps, and risers, respectively. The failure modes for subsea equipment can be seen in Table 2.

Table 2: Subsea equipment - failure modes, from [73]

Equipment class [b]				Failure modes [a]			
Subsea control systems	Xmas trees	Subsea pumps	Risers	Description	Examples	Code [c]	Type [d]
X		X		Failure to function on demand	Failure to respond on signal/activation	FTF	1
	X			Failure to open on demand	Doesn't open on demand	FTO	1
	X			Failure to close on demand	Doesn't close on demand	FTC	1
	X			Failure to lock/unlock	Doesn't lock or unlock when demanded	FTL	1
	X			Failure to set/retrieve	Failed set/retrieve operations	SET	1
X	X	X		Spurious operation	Fails to operate as demanded	SPO	2
		X		High output	Overspeed/output above acceptance	HIO	2
X		X		Low output	Delivery/output below acceptance	LOO	2
X	X			Insufficient power	Lack of or too low power supply	POW	1
X				Loss of redundancy	One or more redundant units failed	LOR	2
	X			Loss of barrier	One or more barriers against oil/gas escape lost	LOB	2
	X		X	Plugged/choked	Partial or full flow restriction	PLU	1
X	X	X	X	External leakage – process medium	Oil, gas, condensate, water	ELP	3
X	X		X	External leakage – utility medium	Lubricant, cooling water	ELU	3
X	X	X	X	Internal leakage – utility medium	Leakage internally of process or utility fluids	INL	3
X		X		Abnormal instrument reading	False alarm, faulty instrument indication	AIR	2 (3)
	X		X	Structural deficiency	Material damages (cracks, wear, fracture, corrosion)	STD	3
X			X	No immediate effect	No effect on function	NON	1
X	X	X	X	Other	Failure modes not covered above	OTH	—

[a] Although not a requirement of this International Standard, it is recommended that, for subsea equipment, failure modes are also recorded at a lower hierarchical level, e.g. "maintainable item".

[b] See Table A.4. The codes shown apply to equipment classes marked with "X".

[c] A proposed abbreviated code for the failure mode.

[d] One of the three failure-mode types listed below; depending on type of failure, more than one of these categories can apply (e.g. a severe leakage can lead to stoppage of the equipment):

1) desired function is not obtained (e.g. failure to start);
2) specified function lost or outside accepted operational limits (e.g. spurious stop, high output);
3) failure indication is observed, but there is no immediate and critical impact on equipment-unit function. These are typically non-critical failures related to some degradation or incipient fault condition.

3.3 Measurement Techniques and Data Utilisation

Regarding maintenance operations ISO 13628-1 [6] emphasises that "planning for maintenance should begin during the design". It also outlines the importance of testing and evaluation for tools and procedures as well as the need for documentation. The standard proposes periodic inspection of seabed equipment. Furthermore "efforts should be made to diagnose and define a problem prior to initiating a maintenance operation." That clearly suggests condition monitoring for seabed equipment.
The following points address the overall design [6]:

- The system shall be designed such that any operation can be suspended, leaving the well(s) in a safe state if predefined operational limits are about to be exceeded.
- The system should be designed for easy fault diagnosis without system retrieval.
- A high system availability should be obtained through use of simple designs and reliable products (supplier's standard equipment preferably with a satisfactory field performance record). The system availability requirement should be established in the design basis information for the development.
- Operational reliability should be documented for the subsea systems. For noncritical and temporary equipment, relaxed requirements may be accepted.

These are further arguments for the implementation of CM in a SPS. Such a technique enables to monitor the system condition and assist in fulfilling the named design requirements.
The estimation of the time to service for a given piece of equipment or a system is based on observable parameters. For these the following three factors are required [74]:

- Measurement or calculation method of the parameter from sensor data
- Model for future behaviour of the parameter
- Operational limit for the parameter

As described in Chapter 2.4.5, fibre optic offers opportunities regarding sensing and data transfer. A test suit for a subsea pump has been presented in the literature [75]. Here fibre optic sensor have been used to monitor temperature of motor windings, pressure and temperature of lube oil, accelerations of pump and motor, and strain in the pump rotor bearings. The latter has detected early stage damage to a rolling element. However, in this test no prognosis of the parameters was included.
To fully utilise the benefit of a CM system it must give a warning sufficiently ahead of time in order to enable the user to plan for an intervention instead of performing

reactive maintenance. This implies that parameters shall not only be monitored but that their future behaviour also needs to be predicted. Additionally, an operational limit for every observed parameter has to be set. All three named factors are necessary in order to estimate time to service and subsequently trigger maintenance actions at the right time.
Figure 20 shows equipment performance over time. As a failure is introduced to the system its performance decreases until it finally fails functionally. This is indicated as point F. The failure can first be detected at a point in time that is marked as P.

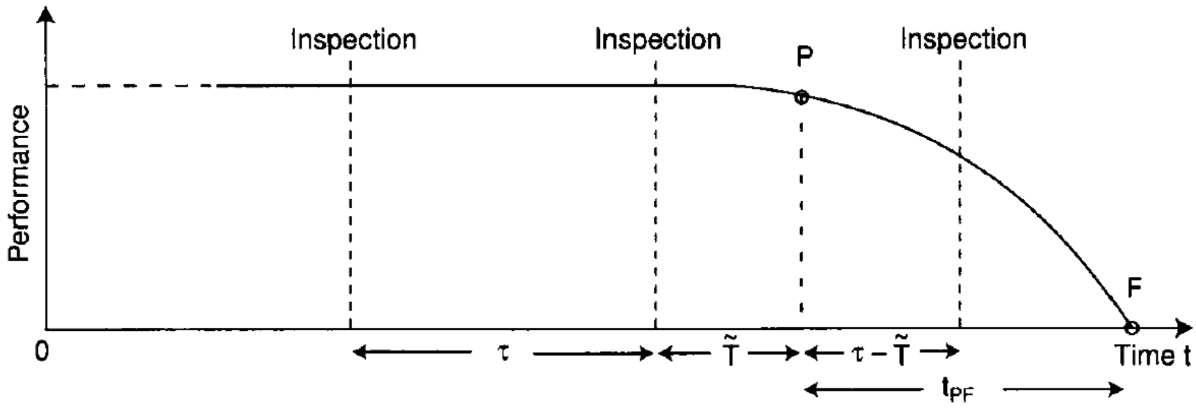


Figure 20: PF-interval model, from [10]

The timespan between P and F depends on equipment properties, failure mode and mechanism as well as operating conditions and is referred to as the PF-interval. If detected within this interval a potential failure can be prevented hence its consequences be avoided.
Aker Solutions documented the monitoring of key performance indicators (KPIs) for pumps being deployed subsea in two different fields. Identified KPIs were lube oil consumption, accumulator bank status, pump performance, vibration, valve actuator profiles, and ball bearing wear and lifetime. Project A was situated in the GoM and project B in the North Sea. Both pump systems were equipped with pressure and temperature sensors, whereas project B had additional vibration sensors. Sensor data as was captured and temporarily stored offshore to subsequently be transferred to an onshore storage. In case of project A data transfer of 1GB per year was documented. For monitoring the system's condition an analysing tool was required. It was fed the gathered data and displayed an alarm in case intervention was required. After two years of testing and operation respectively no major degradations were detected in both projects. [74]
In another more recent example Aker Solutions monitors the qualification prototype of a gas compression plant for the Ormen Lange field. This test run includes several novel parts for SPS applications, such as magnetic bearings, all electric valve actuators

or subsea variable speed drives (VSDs). In this processing facility incoming hydrocarbons are first separated in an inlet scrubber. The liquid is then pumped further by a 400 kW centrifugal pump whereas the gas is compressed in a parallel process by a 12.5 MW gas compressor. Subsequently gas and liquid are recombined and transported to shore in a common flow line.

A CM system separated from the control and safety system collects about 1 million data points per second which are logged at a frequency from 1 Hz up to 10 kHz (e.g. voltages and currents). This yields about 10 TB of data per month. Data is provided in different formats and is transported via a non-redundant 100 Mbit/s network to be stored in a fileserver with automatic replication. Gathered data can then be used for visualisation, calculations and analysis at a later stage using a standard open database connectivity (ODBC) interface. In this test run, the following KPIs are monitored to verify the design [76]: “VSD harmonic content; anti-surge control loop performance; high voltage system transients; structural vibration”. Furthermore these KPIs are visualised or calculated, respectively in order to monitor possible gradual deterioration of equipment with time [76]: “electrical actuated valve travel time and power consumption; magnetic bearing position and current; compressor efficiency; pump efficiency; VSD efficiency”.

During the test Aker Solutions aims to use the CM data not only to monitor equipment deterioration but also for trouble shooting as well as to verify the design and gain detailed knowledge about component behaviour. After two years the pilot will be deployed and operated in the field. Results from the test-phase may lead to the definition of further KPIs and will also be used to develop the actual CBM system. Once in operation, the system is supposed to gather fewer CM data which is then utilized to assist CBM (predicting RUL). [60, 76, 77]

However, in both cases described above no further details about the underlying models for RUL-estimation are given.

GDF Suez, the operator of the Gjøa field has installed a Condition and Performance Monitoring (CPM) system by FMC Technologies in that field. This CPM system consists of an offshore utility for data collection and an onshore CPM server consisting of several modules. The latter is receiving non-processed data from the collector, analyses it and displays the results to the user. Each module checks the respective data gathered either for known failure situations or patterns that indicate abnormal behaviour. In CPM monitored parameters are transferred into a 0-100% value where 0% is non-functional and 100% is functional. That value is named Technical Condition Index (TCI) which is claimed to be more holistic than traditional KPIs since it utilises [78] “all available data and information, where design parameters, criticality, system experience and operating philosophy is modelled into”. This TCI can be displayed per module and is colour coded for easier trouble shooting.

The paper gives three examples where the CPM system assisted in detecting functional failures at an early stage. For the subsea router module, which directs communication from the subsea control module to topside, an increase of internal pressure was observed well before the module actually failed to communicate. This three month period was used to prepare the module change and combine the task with an already planned campaign.
The flow coefficient (C_v) – a measure of a device's fluid flow efficiency – of choke valves can be estimated from fluid properties, flow rate and pressure measurements. As an eroded choke would yield a higher C_v than an unimpaired one deviation between estimated and theoretical C_v-values are monitored by the CPM system. Any abnormalities trigger a notification, and so a choke valve with damaged cage could be identified.
In the Gjøa field, valves are operated by a hydraulic PCS. A direction control valve (DCV) directs hydraulic fluid from the supplying conduit to the valve actuator or from that actuator to the discharge line. Hydraulic fluid leakage across the DCV may occur for many different reasons and will cause an abnormally large fluid consumption as the system tries to maintain pressure. In the example given, the leakage was too small to be detected by the flow meter installed. Additional monitoring of differential pressure across the DCV made it possible to identify the malfunctioning item and reset its position. Here the CPM system allowed cutting short an otherwise tedious analysis that would have taken days or even weeks and enabled the operator to find the malfunctioning device within a single day. [78]

3.4 Organisation of Maintenance for Subsea Production Systems

So far, different strategies have been described, failure prone components have been named and examples for data acquisition and utilisation have been given. The following paragraphs try to shed light on the companies' actual efforts to organise maintenance and how these are put into practice.
A case study carried out by [63] tried to identify activities that are carried out to maintain SPS. Therefore ten experts from eight different companies (including operators, equipment manufacturers and IMR service providers) were interviewed. The study states that a strategy for how to i.a. maintain a subsea installation is influenced by factors like operator philosophy, legislation or local issues. Furthermore such a strategy is built on project scope and individual preferences.
Since every intervention for modification or IMR is very costly for SPSs they are designed very robust and may be sturdy enough to operate for 20 to 30 years under extreme conditions. A modularised approach is chosen to easily replace parts of the system which can then be serviced at the supplier's workshop if needed. SPSs and

their components are analysed and subsequently classified according to their criticality. Also the impact of a possible failures as well as the estimated repair time is taken into account. That allows identifying critical system components that are inspected regularly to prevent failures due to wear out. The operator specifies requirements for the system, the integrity management as well as the maintenance strategy. It is the manufacturer's duty to demonstrate the pros and cons as well as cost/benefit analysis for every proposed design solution and maintenance strategy. In case an IMR service provider will be in charge of the maintenance activities, that provider will we included in the discussion. All these inputs enable the operator to select the best overall solution. Project teams of all parties involved will be in regular discussion as the project proceeds.

In terms of reliability and quality of systems over their lifetime experience from earlier projects is vital. The collection of Offshore and Onshore Reliability Data (OREDA) provides input for e.g. likelihood of failures. Additionally, results from CM are used to assist in the planning of maintenance activities. A strategy for critical spare parts has to be decided upon. It should be considered to keep them in stock as this might be cheaper than the costs evolving from additional downtime due to waiting for equipment. Special attention shall therefore be given to long lead items. Obsolescence of components may also be an issue. However, manufacturers usually provide a kit of spare parts for the components that are more likely to fail according to their experience and several different kinds of contracts are possible.

Planning for maintenance activities is either based on recommendations made by the vendor or the supplier's specifications. Water depth of the installation needs to be considered as it influences the decision to use either divers or alternatives such as remotely operated underwater vehicles (ROVs), autonomous underwater vehicles (AUVs) or remotely operated tools (ROTs). Depending on the geographic location, weather conditions can influence maintenance activities. For example, due to harsh conditions in the winter activities are preferably carried out during summer in the North Sea whereas in the GoM maintenance can be carried out all year. Still, the hurricane season has to be accounted for in the latter location. Technologies such as active heave compensated cranes or deck skidding systems aboard of intervention vessels have reduced activity stoppages due to bad weather and helped to optimise operations. However, the risks involved in lifting subsea equipment and crane capabilities have to be identified. Deployed vessels need to be equipped with sufficient lifting arrangements. Additionally their availability has to be provided – especially for unexpected failures, hence operation on short notice. Simulation models are generated to account for mobilisations interventions, maintenance activities as well as disruptions e.g. due to weather. These provide the basis for negotiating frame agreements with vessel contractors. [63]

ROVs are used for activities such as deploying equipment, replacing components, operating valves, and performing cleaning campaigns or visual inspection surveys. In the decision where and how to inspect RBI methodology is often used. Inspection results are analysed by the equipment manufacturer who will then give advice to the operator. The integrity management process has been described in [79]. It comprises of four main activities, which are [79]:

- Risk Assessment and Integrity Management 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
- Planning and execution of required Mitigation, Intervention and Repair activities.

These are illustrated in Figure 21.

Figure 21: The integrity management process, from [79]

In the risk assessment, any threats that could directly or indirectly put the systems integrity at risk should be identified and evaluated. Inspection, monitoring and testing

activities aim at gathering information for establishing a components current condition and to analyse its level of degradation. In case an abnormality is detected, the components current condition as well as the possible impact of the abnormality should be evaluated. If the components level of integrity is not deemed satisfactory for further operation immediate actions are needed. However, if there is an acceptable safety margin a component may be operated temporarily, until the present abnormality has been repaired or removed. [79]
After concluding an intervention the lessons-learnt system is used to identify and document any events, factors or issues which could influence future operations. To successfully carry out maintenance and intervention activities, communication between all parties (operators, equipment manufacturers and IMR service provider) is essential. [63]

3.5 Challenges and Constraints

Subsea systems generate a vast amount of data. However, key is that all the data available is utilised to fulfil the purpose of a PM strategy. In today's applications this is most of the time not the case [80]. This is also supported by [59], which states that "a lot of complex and expensive CM equipment has been installed, often without a sound scientific basis."
CM can reduce the number of critical failures. However, it is also assumed that it induces a certain number of unnecessary maintenance actions. This is crucial, since there is a certain risk associated with maintenance operations. Accidents may occur during or because of inadequate maintenance. Additionally such an operation may itself introduce additional failures to the system. It is important to note here that a system does not get more reliable just because it is maintained more often. An effective PM strategy will however ensure realisation of the systems inherent reliability. Improved system reliability can be achieved by redesign or modification only, e.g. by introducing redundancy. [59]
One of the biggest challenges in subsea maintenance is connected to the accurate prediction of component behaviour. Models for prognosis do exist but Rausand [59] "the relationship between a condition measurement and the remaining time to failure is in many cases not fully understood". This again effects the selection of maintenance intervals.
Generally, a gap between theory and reality of maintenance is perceived. Particularly there is an isolation of maintenance practitioners and reliability engineers on one side and the [59] "statisticians and operation researchers working with maintenance optimisation models" on the other. This isolation is said to be higher than in any other

professional activity [81].
It is furthermore important, that the maintenance strategy fits the company's total maintenance system. In case of an RBI programme quantitative approaches are for example very demanding regarding volume of data and its required level of detail. Complexity of the RBI methodology and lack of buy-in by at least part of the launching organisation were identified as possible reasons for failure of programme implementation. In case consultants are involved it is essential that they have a full understanding of both the programme to implement and the plant or systems involved. [65]

Chapter 4

Analysis

As discussed, failures in SPSs are costly because of the need for special equipment, trained personnel and logistic challenges related to maintenance operations.
Chze [80] identified PCSs as the highest contributors to the total amount of failures in SPSs. This analysis shall therefore evaluate a PCS. As multiplex-hydraulic systems are the prevalent type among all SPS deployed the studied system is of such kind which has been described in section 2.4.5.
The main aim of this analysis is to identify critical components within the PCS and to reveal the potential for condition monitoring. Possibilities for placement of sensors that can provide up to date information about a components' status shall be pointed out. This information can then be used further for performing CBM, thus responding to a reduction in availability accordingly.

Data Sources

This analysis is performed based on the description of a PCS in chapter 2.4.5, the work of Sætre [82] and Bitanov [83] as well as the failure modes stated in ISO 14224 [73], which are shown in Table 2, and relevant failure rates from SINTEF et al. [12].

4.1 Methodology

4.1.1 Failure Mode, Effects and Criticality Analysis

Already mentioned in 3.1.2, a FMECA is generally performed to audit reliability and criticality of single components independent of the chosen maintenance strategy and is often the first step in a system reliability study. To identify failure causes and failure modes as well as their effects as many subsystems, assemblies, and single components as possible are reviewed. The findings are recorded in a worksheet. Other approaches to identify hazards or undesired events are hazard and operability study

(HAZOP) or hazard identification (HAZID) [11].
In a FMECA criticalities or priorities are assigned to failure mode effects. It is mainly a qualitative analysis that should be carried out during the design phase of a system. That is to identify areas that need improvement in order to meet reliability requirements. It also serves as basis for design reviews and inspections.
Other purposes of a FMECA are e.g. to [10] “list potential failures and identify the magnitude of their effect” as well as to [10] “provide a basis for quantitative reliability and availability analyses”.
No FMECA for a PCS was carried out during this work. This is since the following reliability and availability/failure tree analysis was based on earlier work rather than on a failure analysis like a FMECA (see 4.1.4). However, a FMECA for a SCM (or control pod), which is part of the PCS, has been carried out by [83].

4.1.2 The Concept of Safety Integrity [7, 8, 11]

A PCS performs a number of safety related control functions and its reliability performance shall be evaluated in accordance with industry standards. Therefore it is necessary to link PCSs to an already established regulatory environment. The concept of safety integrity which is applied in the standards [7] and [8] offers the possibility to evaluate the reliability performance of safety instrumented systems.
Applying this concept to PCSs asks for the compliance of PCSs with the definition of safety instrumented systems (SIS). Per definition a SIS is an instrumented system used to implement one or more safety instrumented functions (SIFs) [8]. At least three sub-systems [sensor(s), logic solver(s), and final element(s)] make up the SIS. These subsystems must work jointly to detect a deviation (i.e. demand) and in such a case avert potential danger to the equipment under control (EUC). This is done by performing so called SIFs that are designed to bring the EUC to a required safety integrity level (SIL).
The PCS has been described in 2.4.5. Besides activation during continuous control operation the system’s functions may also be triggered by physical interaction based on the operating personnel’s knowledge. Furthermore Bitanov [83] notes that the SCM “may be operated not on a continuous basis, only when the demand occurs: an example is to activate a necessary valve”.
As a “SIS is mainly intended for dedicated safety systems that automatically respond to a process demand through the use of SIFs” [82] a PCS might not align with the SIS definition to full extent. Nevertheless it is mentioned in NOG-070 [9]. This guideline adapts IEC 61508 and IEC 61511 for the application in the Norwegian petroleum industry and states PFD/SIL requirements for different safety functions.
Depending on which standard is applied, SIFs are divided into different groups relating

to their mode of operation. According to IEC 61508-1 [7] such functions that are operated in low-demand mode require the measure of average probability of (dangerous) failures on demand (PFD) to quantify their reliability performance. For SIFs in high-demand mode and continuous demand mode the according expression is the average PFH.

Bitanov [83] concludes that PFH is the preferred reliability performance measure for a PCS. That is because a PCS is considered as a SIS that performs several safety-related control functions which may be classified as proactive. Therefore the PCS's SIFs can be regarded as operating in continuous mode. The qualified standard for SISs in the process industry (including the oil and gas industry), IEC 61511 [8], leaves the user free to decide between PFD and PFH when assessing a SIF's reliability. However, as stated above, IEC 61508-1 [7] requires the reliability performance to be expressed as PFH for SIFs in continuous mode of operation. Target failure measures for the fulfilment of according SILs are given in Table 3.

Table 3: Safety integrity level requirements, from [7]

Safety integrity level (SIL)	**Average frequency of a dangerous failure of the safety function [h^{-1}] (PFH)**
4	$\geq 10^{-9}$ to $< 10^{-8}$
3	$\geq 10^{-8}$ to $< 10^{-7}$
2	$\geq 10^{-7}$ to $< 10^{-6}$
1	$\geq 10^{-6}$ to $< 10^{-5}$

It shall be noted that for a SIF operated in continuous mode the term *dangerous* is interpreted as follows [11]: "A *dangerous failure* is a failure that terminates the ability of the SIS to carry out its safety function according to the performance requirements. This means that all failures to perform a SIF are dangerous failures."

4.1.3 Fault Tree Analysis [10, 11]

A fault tree is an interrelationship diagram showing the logic dependencies between a potential critical event (the TOP event) in a system and the causes for this event. These causes are at the lowest level called basic events and may be normal events (i.e., events that are expected to occur during the operational life of the system), environmental conditions, human errors, and specific component failures. Depending on its scope, a fault tree analysis (FTA) may be quantitative, qualitative or both. The main objectives of an FTA are [11]:

- To identify all possible combinations of basic events that may result in a critical event in the system.

- To find the probability that the critical event occurs during a specified time interval or at a specified time t, or the frequency of the critical event.
- To identify aspects (e.g., components, safety barriers, structure) of the system that need to be improved to reduce the probability of the critical event.

4.1.4 Reliability Performance Quantification

The reliability performance for the safety function “Isolate the subsea well from the flowline by closing the production master valve (PMV)” was determined by applying the method of PFH. Therefore a fault tree was built with the CARA FaultTree software first. Every basic event in the fault tree was assigned a failure rate. Additionally the importance of every basic event was calculated using the CARA software. Time-steps had to be set to define the number and interval of output data. With these inputs the PFH for the TOP event ”PCS fails to activate PMV” was calculated for every time-step and plotted over time using Microsoft Excel. The average $\mathrm{PFH_G}$ value over the mission time of 20 years was then derived from this function.

Fault Tree Development

The fault tree for the actual application was derived from the one used in [82]. This was done after it had been verified that the functional principles of a subsea BOP control system and a PCS for controlling a valve are comparable (supported by Prof. Sangesland, NTNU, Department of Petroleum Engineering and Applied Geophysics). Still, the fault tree had to be modified in order to depict the actual components. Additionally, failure rates for PCSs are different from those for BOP control systems. Failure modes and the according failure rates were primarily taken from [12]. However, not all of the basic events depicted in the fault tree were documented therein, hence no failure rates were available. For these cases alternative failure rates from linked events in [12] as well as failure rates used in [82] were considered and balanced against each other. The most conservative failure rates were chosen for all cases. These as well as the fault tree can be found in Appendix B.
The TOP event in the FTA relates to the PCS’s ability to close the PMV upon request. The scope of the analysis starts after the process has been activated via the master control station and ends when the PMV is activated. That means that human factors and the actual ability of the PMV to close are not considered in this analysis.

Minimal Cut Sets

Rausand and Høyland [10] define a cut set in a fault tree as “a set of basic events whose occurrence (at the same time) ensures that the TOP event occurs. A cut set is said to be minimal if the set cannot be reduced without losing its status as a cut set.” Further [10]: “The number of different basic events in a minimal cut set is called the order of the cut set.”
In the current fault tree there are 16 different cut sets and the maximum cut set order is 2. This value was further used as input parameter when determining the component importance.

Component Importance

In a system, some components are more important for the system reliability than others. Generally components in series with the rest of the system (and therefore with a cut set order of 1) are of higher importance than a component that is part of a cut set of higher order. Importance measures can identify the basic events within a fault tree diagram for which high-quality data needs to be obtained as well as the ones with the greatest need for improvement, maintenance, or control.
Several measures are available to rank components according to their importance. Component importance always relates to a specified system function. That is relevant, as a component may be essential for one function whereas it may have little or no function in others. [10, 11]
The following measure of the component importance for a basic event i in a fault tree was proposed by Birnbaum [84]:

$$I^B(i|t) = \frac{\partial Q_0(t)}{\partial q_i(t)}$$

for $i = 1, 2, ..., n$. This equation shows, that the importance measure is obtained by partial derivative of the probability that the TOP event occurs at time t, $Q_0(t)$, with respect to $q_i(t)$, the probability that the basic event i occurs at time t. This approach represents a classical sensitivity measure. [10, 11]
For determination of component importance a built in tool within the CARA FaultTree software has been used. The according input window is shown in Figure 22.

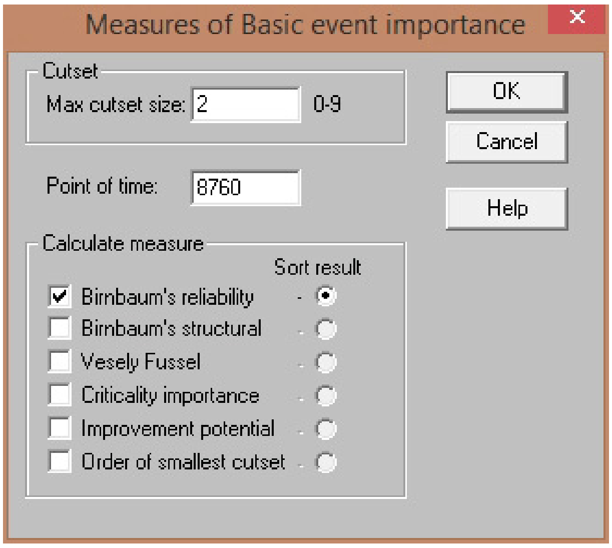


Figure 22: Input mask of CARA FaultTree software for the calculation of component importance

As component importance varies over time it was calculated for several time-steps within the mission time. The input for *Point of time* was therefore adjusted accordingly. Component importance over time is shown in Figures 26 and 27 in Appendix B.

Average Frequency of Dangerous Failures per Hour

Rausand [11] provides a method to calculate PFH based on a fault tree analysis for so-called *voted groups* which is denoted by G. According to [11] it is assumed that such group is part of a safety loop which performs a specific SIF. This means that in case the group fails the SIF fails as well. The method uses Birnbaum's measure of importance (see above) for expressing the probability of a basic event being critical for a TOP event to occur.
The instantaneous $\mathrm{PFH_G(t)}$ related to a SIF is [11]:

$$\mathrm{PFH_G(t)} = \sum_{i=1}^{n} I^B(i|t) w_i(t) \tag{1}$$

Over the time interval (0, τ) the average $\mathrm{PFH_G(t)}$ is given by [11]:

$$\mathrm{PFH_G}(0,\tau) = \frac{1}{\tau}\int_0^{\tau} \sum_{i=1}^{n} I^B(i|t) w_i(t)\, dt \tag{2}$$

Here, $w_i(t)$ denotes the unconditional rate of occurrence of the basic event i whereas n is the number of basic events in the fault tree. Since in the current case i denotes an event where a *single channel* (one or more elements that perform a safety function) within a voted group gets a failure with failure rate $\lambda_{D,i}$, this yields $w_i(t) = \lambda_{D,i}$. Since in the current case Birnbaum's measure of importance is not constant over time, however, this results in:

$$\mathrm{PFH_G}(0,\tau) = \frac{1}{\tau}\int_0^{\tau}\sum_{i=1}^{n} I^B(i|t)\lambda_{D,i}\,dt \tag{3}$$

The instantaneous $\mathrm{PFH_G(t)}$ has been calculated by solving Equation 1 for every time step. Results were plotted over time in Microsoft Excel. Using the program's option to project a trend in the data on hand led to an exponential function showing the best fit. This function was subsequently plugged in in Equation 3 to calculate the average $\mathrm{PFH_G}$ over the mission time.

4.2 Results

The reliability quantification of the TOP event "PCS fails to activate PMV" was carried out for a timeframe of 20 years (175200 hours). Calculation of the average $\mathrm{PFH_G}$ resulted in a value of 8.56×10^{-6} failures per hour. As per NOG-070 [9] the investigated safety function "Isolate the subsea well from the flowline by closing the PMV" shall fulfil at least a SIL 1 requirement. According to Table 3 this requirement can be translated to a PFH value in the range of $\geq 10^{-6}$ to $< 10^{-5}$. Since the calculated $\mathrm{PFH_G}$ is 8.56×10^{-6} failures per hour the analysed safety function does fulfil this requirement and can therefore claim the SIL 1 level.
Figure 23 shows the behaviour of $\mathrm{PFH_G}$ over time as well as the average $\mathrm{PFH_G}$.

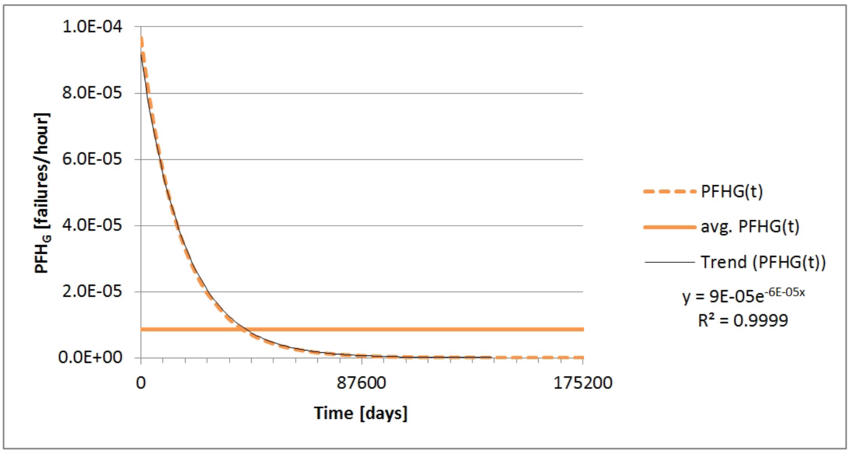


Figure 23: PFH over time

4.3 Discussion

Successful fulfilment of the SIL requirement implies that the investigated safety function is deemed to be a SIF (wherefore SIL allocation is a prerequisite). However, it is not possible to derive the reliability of the SIS (in this analysis the PCS) from the reliability of that single function. [11] “A SIS may perform one or more SIFs. To say that the reliability of a SIF is the same as the reliability of the SIS (that is performing the SIF) is therefore at best imprecise”.
Largest contributors to this result were components such as the pressure regulator, the SUTA, the surface pilot valve as well as different electric or electronic problems. These components and their associated basic events respectively showed both comparably high failure rates and high component importance. On the contrary, hydraulic umbilicals, SEMs, the accumulator, and leakage in the SCM contributed only very little to the result. This was due to their associated basic events' individual PFH values which were in the order of magnitude of 1×10^{-12} or less. Although e.g. SEMA and SEMB had rather high failure rates their importance was comparably low resulting in the low PFH value.
The absence of an FMECA for the analysed system carries the risk of misjudging the effect of failures or to overlook some failure modes entirely. Additionally, the fault tree was merely derived from a comparable system. This might be considered as another weakness in the analysis. However, additional failure modes would increase the $\mathrm{PFH_G}$ value and would make complying with SIL requirements even more difficult.
The individual PFH values may also be used to identify basic events with the greatest need to be controlled. As they are top-ranked in the analysis the pressure regulator, the SUTA, the surface pilot valve, and electric and electronic components are recognised as potential candidates for monitoring.
The pressure regulator is basically a valve that adjusts the hydraulic pressure before it is directed to the SCM and further to the actuator. Same as for the surface pilot valve position, valve actuator profile, and differential pressure are possible parameters to monitor which would help in estimating the components state and detecting a malfunction. For both failure modes EEF and FCEEH descriptions are worded in rather general terms which make suggestions for monitoring in the underlying electric or electronic parts difficult. At this point it shall be questioned if the recording level of failure modes is low enough as recommended in ISO 14224 [73]. However, (output) currents and voltages may be monitored as well as electrical power consumption.
Regarding the SUTA, several factors have to be considered. Pressure sensors can provide information about possible leakage. In case the SUTA includes valves the same parameters as named for the pressure regulator and the surface pilot valve shall be introduced. Additionally, excessive bending moments introduced in the flanges espe-

cially during possible lifting may lead to fatigue failure. This may therefore be monitored by strain gauges.
As discussed in section 3.5 an effective PM strategy is able to ensure realisation of the systems inherent reliability but is not able to improve it. A way to increase the systems reliability and hence reducing the criticality of single components would be to introduce redundancy to the system. However, the failure mode descriptions for the top-ranked basic events are given in quite general terms. This makes it difficult to understand which particular component fails and in what way this component fails exactly. Again, as mentioned above, the recording level of failure modes may not be sufficient. In any case a more detailed assessment of the failure modes as well as an in depth design analysis would be needed in order to be able to reveal potential for enhancing the reliability. It is therefore not possible at this stage to propose any system modifications.
Since human factors have been neglected in this analysis the presented result may be somewhat limited. Situations may occur where human judgement rather than the control system will take the decision to operate the PMV. Quantification and modelling of human factors may be difficult. A discussion about the effects of human factors in well integrity may be found in [85].

Chapter 5

Conclusion

5.1 Summary and Conclusions

Three main objectives were addressed in this work. The first was to describe SPSs and the equipment involved. This was successfully addressed by carrying out an extensive literature study (see chapter 2). A SPS was defined as [13] ”system that transports reservoir fluids from the subsurface reservoir to the surface, processes and treats the fluids, and prepares the fluids for storage and transfer to a purchaser”. Thereby at least parts of the system are placed under water. In more recent developments the degree of sub-systems placed subsea was extended and this trend is expected to continue in the future. That is because operators strive to increase the economic value of offshore field developments. As an example the Statoil Subsea Factory™ concept was mentioned.
The literature study revealed the special role SPSs take on in developing offshore hydrocarbon resources. Typical applications are in marginal or satellite fields. It was also shown that SPSs may create early revenues in a project. As these can shorten the payback period, an economic decision criterion, SPSs can become the decisive factor in a projects investment decision.
Additionally different system configurations and their components were described as well as possibilities for monitoring the system’s state.

The second objective was to provide an overview of maintenance concepts for SPSs. For approaching this objective a literature study was performed too which was implemented in chapter 3. Objectives for a maintenance program were outlined. Production availability as well as HSE performance were found to be prime measures in a successful maintenance strategy. Different strategies as well as the selection process were described in detail. Additionally failure prone items and common failure modes were presented.
Mature systems that were deployed in the field for years are designed to avoid any

kind of intervention. This advantage is bought by CAPEX spending at an early project stage for introducing redundancy to the system. Usually only rather basic monitoring equipment is used. In contrast new SPSs are tremendously complex and therefore demand a high level of monitoring to ensure reliability. However, there are not many field examples available since most of these systems were only deployed recently. A discussion with OMV Norge AS confirmed these impressions the author received from literature.
The objective to give an insight in industry practices could only be met partly. No detailed documentation of data processing and failure prediction methods involved in CBM or RCM activities could be found in the literature. Instead a lot of in-house developed concepts not revealing any particulars were discovered which could therefore not be evaluated qualitatively. However, contents of a case study provide information on general maintenance organisation and activities for SPSs.

With an analysis described in chapter 4 the third objective was addressed. The PCS was chosen as a suitable sub-system for demonstrating reliability quantification as well as to reveal the potential for CM. Calculation of average $\mathrm{PFH_G}$, the reliability measure, for the safety function “Isolate the subsea well from the flowline by closing the PMV” yielded a value of 8.56×10^{-6} failures per hour over a mission time of 20 years. This corresponds to a SIL of 1, just as required by NOG-070 [9], which also confirms the status as a SIF for the investigated function.
However, some areas for improvement could be pointed out as key contributors to this result were identified. Suggestions for CM of the pressure regulator, the SUTA, the surface pilot valve, and electric and electronic components have been made.

5.2 Recommendations for Further Work

With regard to the uncertainties in the performed analysis in chapter 4 some recommendations for future research are made.
For further reliability analyses it is recommended to carry out a FMECA first. As this evaluation starts from scratch (instead of with a congeneric system) and involves experts from different disciplines, hence different perceptions of the system, there is no room for preconceived opinions. Thus this kind of evaluation will ensure that all the relevant failure modes are perceived and can subsequently be considered in the fault tree analysis. These adaptions will increase the validity of a reliability analysis even further. Additionally, a comparison to the current study can be drawn in order to assess the value added by including a FMECA. That will allow comprehending if the higher effort of carrying out this additional analysis is reasonable in the current case. Collat-

ing the results of the respective reliability quantifications will give an indication of the significance of a FMECA when investigating a safety function.
Besides that, data gathering specifically for the particular failure modes identified in the FMECA shall be targeted. The respective failure rates for failure modes that are part of the updated fault tree therefore need to be noted directly rather than being derived from related failure data. A recording of data at ”maintainable-item” level as suggested in ISO 14224 [73] shall be ensured in order to enable analyses that allow for expedient recommendations for system improvement. In general as data recording will most likely continue to expand, more recent and larger amounts of data should be available for future analyses, too.
Moreover the reliability of other safety functions, e.g. related to the downhole safety valve, is also of interest and may therefore be quantified. An approach similar to the one described above shall be utilized in such an evaluation.

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Appendix A

Definitions

This thesis uses vocabulary in line with certain standards. Important general terms can be found below.

A.1 Terms defined in ISO 13372 [67]

Function

normal or characteristic action of a machine or the system of which it is part

Failure

termination of the ability of an item to perform a required function
NOTE 1: Failure is an event as distinguished from fault, which is a state
NOTE 2: Failure is the manifestation of a fault
NOTE 3: A complete failure of the main capability of a machine is a catastrophic failure (as defined by the end user)

Fault

condition of a machine that occurs when one of its components or assemblies degrades or exhibits abnormal behaviour, which may lead to the failure of the machine.
NOTE 1: A fault can be the result of a failure, but can exist without a failure
NOTE 2: Planned actions or lack of external resources are not a fault

Failure mode

observable manifestation of a system fault

Reliability

Probability that a machine will perform its required functions without failure for a specified time period when used under specified conditions.

Machine

mechanical system designed expressly to perform a specific task, such as the forming of material or the transference and transformation of motion, force or energy
NOTE: This is also sometimes referred to as equipment

Equipment

machine or group of machines including all machine or process control components

System

(in condition monitoring and diagnostics) set of interrelated elements that achieve a given objective through the performance of a specified function

A.2 Terms defined in IEC 61511 [8]

safety function

Function to be implemented by one or more protection layers, which is intended to achieve or maintain a safe state for the process, with respect to a specific hazardous event

safety instrumented function (SIF)

safety function to be implemented by a safety instrumented system (SIS)
Note 1: A SIF is designed to achieve a required SIL which is determined in relationship with the other protection layers participating to the reduction of the same risk.

safety instrumented system (SIS)

Instrumented system used to implement one or more SIFs
Note 1: A SIS is composed of any combination of sensor(s), logic solver(s), and final element(s) (e.g., see Figure 6). It also includes communication an ancillary equipment (e.g., cables, tubing, power supply, impulse lines, heat tracing)
Note 2: A SIS may include software

Note 3: A SIS may include human action as part of a SIF (see ISA TR84.00.04:2015, part 1).

safety integrity level (SIL)

discrete level (one out of four) allocated to the SIF for ecifying the safety integrity requirements to be achieved by the SIS
Note 1: The higher the SIL, the lower the expected PFDavg for demand mode or the lower the average frequency of a dangerous failure causing a hazardous event for continuous mode.
Note 2: The relationship between the target failure measure and the SIL is specified in Tables 4 and 5.
Note 3: SIL 4 is related to the highest level of safety integrity; SIL 1 is related to the lowest
Note 4: This definition differs from the definition in IEC 61508-4:2010 to reflect differences in process sector terminology.

safety integrity requirements

set of the IEC 61511 requirements which shall be satisfied by a SIS to claim a given SIL for a SIF implemented by this SIS
Note 1: The safety integrity requirements are strengthened when the related SIL increases.

Appendix B

Fault Tree Analysis

B.1 Fault Tree

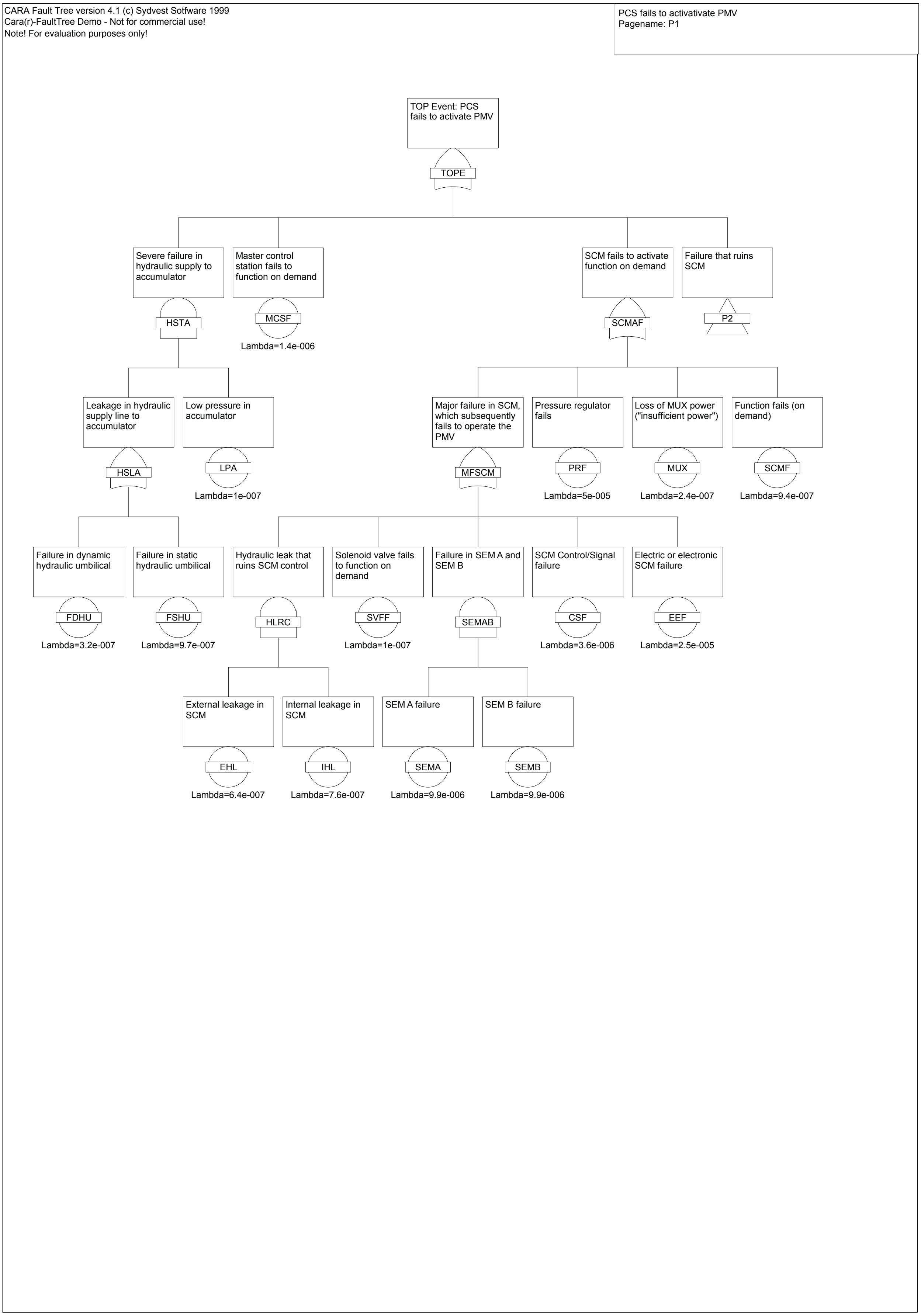

Figure 24: The fault tree used for the FTA, part 1

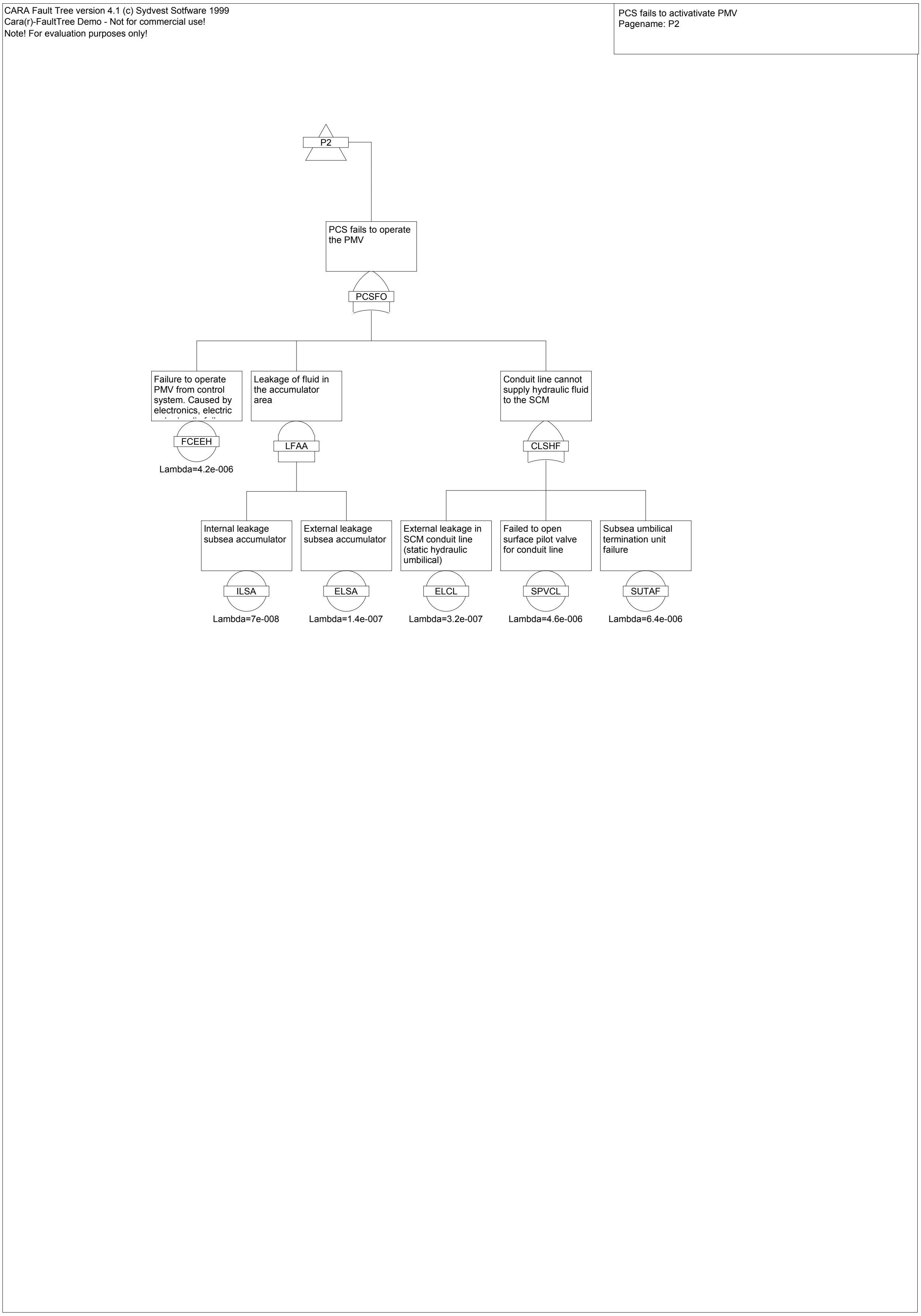

Figure 25: The fault tree used for the FTA, part 2

B.2 Basic Events

The basic events of the fault tree can be found in Table 4. Failure rates $\lambda_{\mathrm{D,i}}$ were taken from [12] except the ones marked with colour which where adopted from an earlier study performed by Sætre [82]. Hereby, values indicated in green are taken from [86], the value marked in orange is taken from [87], and the value marked in red is "expert judgement".

Table 4: Basic events and their failure rates as used in the FTA

Basic event	Failure mode description	$\lambda_{D,i}$ [1/h]
CSF	Control/Signal Failure	3.57E-06
EEF	Electric or electronic SCM failure	2.50E-05
EHL	External leakage in SCM	6.40E-07
ELCL	External leakage in static hydraulic umbilical	3.20E-07
ELSA	External leakage in subsea accumulator	1.40E-07
FCEEH	Failure to operate from control system caused by electronics, electric or hydraulic problems	4.17E-06
FDHU	Failure in dynamic hydraulic umbilical	9.70E-07
FSHU	Failure in static hydraulic umbilical	3.20E-07
IHL	Internal leakage in SCM	7.60E-07
ILSA	Intenal leakage in subsea accumulator	7.00E-08
LPA	Low pressure in accumulator	1.00E-07
MCSF	Master Control Station fails to function on demand	1.42E-06
MUX	Insufficient power	2.40E-07
PRF	Pressure regulator fails	5.00E-05
SCMF	SCM function fails on demand	9.40E-07
SEMA	SEM A failure	9.90E-06
SEMB	SEM B failure	9.90E-06
SPVCL	Failed to open surface pilot valve for conduit line	4.58E-06
SUTU	Subsea umbilical termination unit	6.41E-06
SVFF	Solenoid valve fails to function on demand	1.00E-07

Birnbaum's measure of importance I^{B} has been calculated for several time steps within the mission time. Figures 26 and 27 show the trends of the importance measure over time for every basic event.

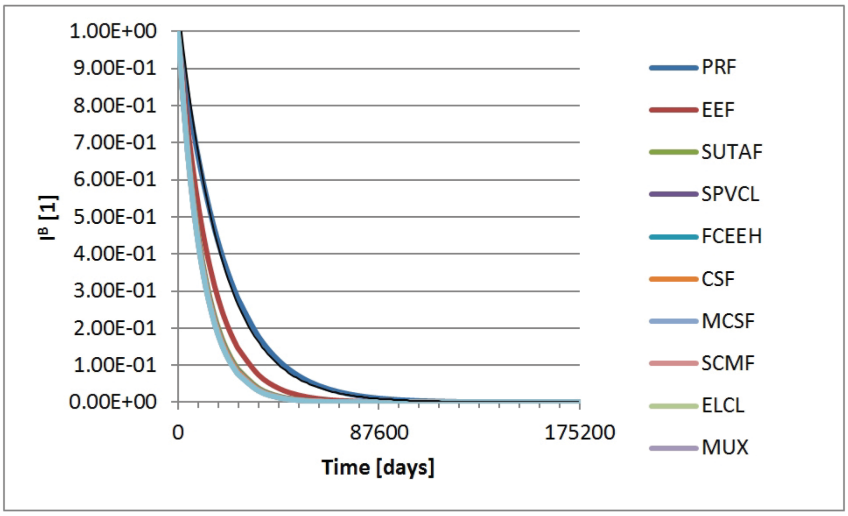

Figure 26: I^{B} over mission time for basic events with order of minimal cut-set of 1

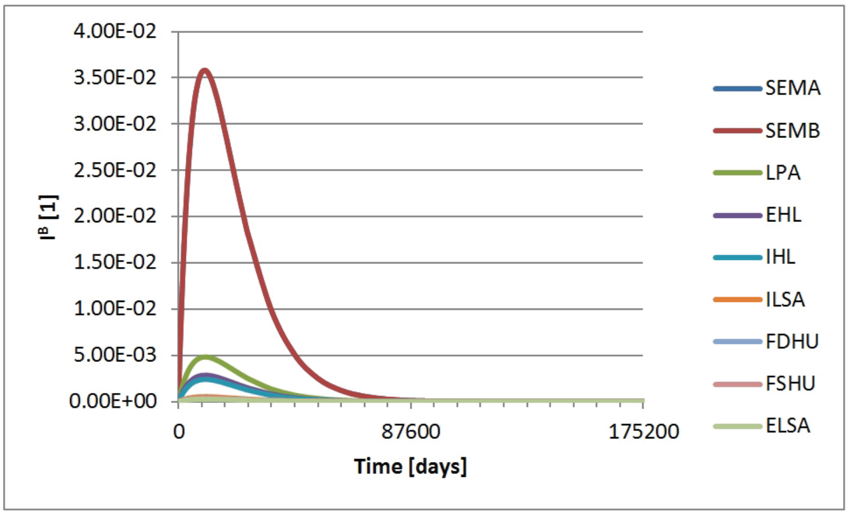

Figure 27: I^{B} over mission time for basic events with order of minimal cut-set of 2

PFH has been calculated for all the individual basic events for several time steps within the mission time. Figures 28 and 29 display the trends of individual PFHs over time.

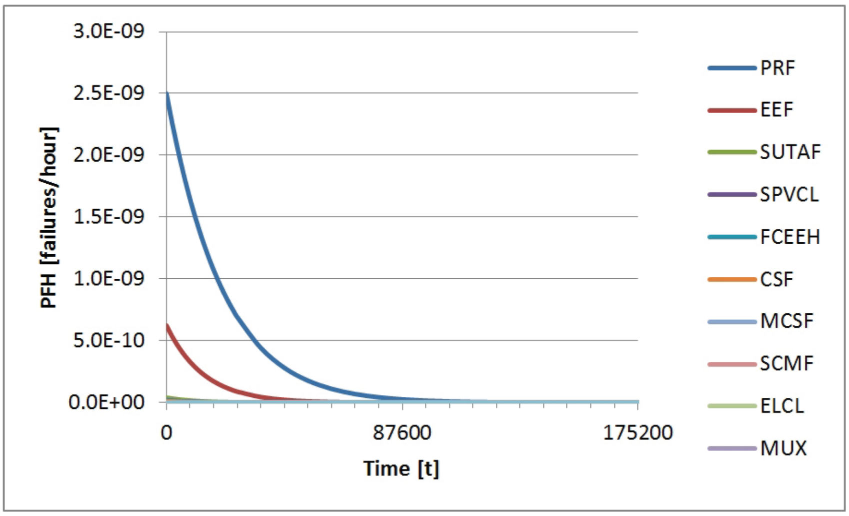

Figure 28: PFH over mission time for basic events with order of minimal cut-set of 1

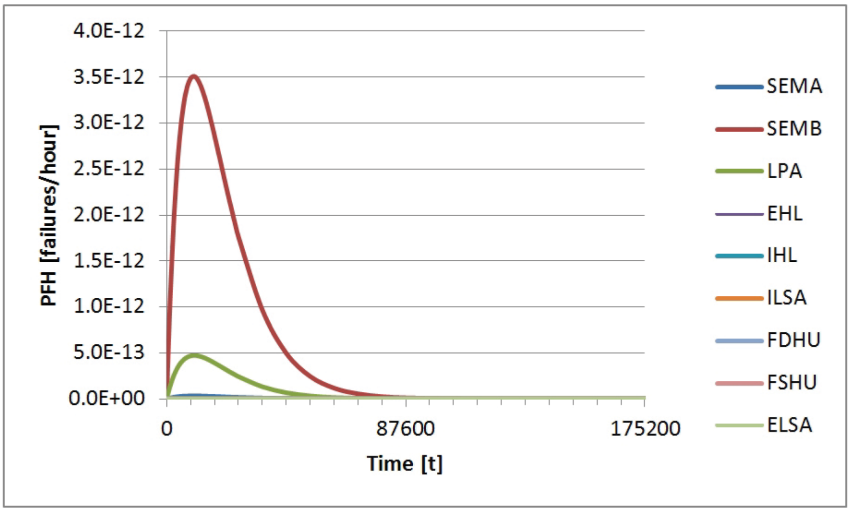

Figure 29: PFH over mission time for basic events with order of minimal cut-set of 2