# Application of Layers of Protection Analysis (LOPA) for subsea production systems

- A risk based model for determination of integrity levels in a global perspective

*Christoffer Clarin*

---

Department of Fire Safety Engineering and Systems Safety
Lund University, Sweden

Brandteknik och Riskhantering
Lunds tekniska högskola
Lunds universitet

Report 5428, Lund 2013

# Application of Layers of Protection Analysis (LOPA) for subsea production systems

- A risk based model for determination of integrity levels in a global perspective

**Christoffer Clarin**

**Lund 2013**

**Title**: Application of Layers of Protection Analysis (LOPA) for subsea production systems - A risk based model for determination of integrity levels in a global perspective

**Author**: Christoffer Clarin

**Report 5428**
**ISSN: 1402-3504**
**ISRN: LUTVDG/TVBB-5428-SE**

**Number of pages**: 112 (including 33 appendix pages)
**Illustrations**: Christoffer Clarin, if nothing else is stated.

**Keywords**: Failure frequency, failure mechanisms, hydrocarbons, leakage, LOPA, LOPA-credit, offshore, oil, protection layers, SIL, SIS, subsea, subsea system.

**Sökord**: Felfrekvens, felmekanismer, hydrokarboner, läckage, LOPA, LOPA-credit, offshore, olja, skyddsbarriärer, SIL, SIS, subsea, subsea system.

**Abstract**: Depletion of onshore and shallow water reserves, in combination with new subsea technology, has made the petroleum industry advance into deeper water. However, new technology also brings new risks. Since most widely accepted standards and regulations are not directly aimed for subsea systems, new methods have to be developed. By developing a LOPA-model, which can be used specifically for subsea context, this thesis intends to be a part of filling that gap. The models main objective is to evaluate subsea production system risk and to determine the appropriate safety Integrity level (SIL) for all present independent protection layers. The method is semi-quantitative in nature, which means that the model output is based on a combination of generic statistical data, expert judgement and logical reasoning. According to the model validation, the result seems to be credible due to what is economically and technically feasible. For example, when a single satellite well subsea system was evaluated it ended up with SIL3 requirements for the “isolation of well function” and lower SIL requirements for other less critical safety functions.



Brandteknik och Riskhantering
Lunds tekniska högskola
Lunds universitet
Box 118
221 00 Lund

brand@brand.lth.se
http://www.brand.lth.se

Telefon: 046 - 222 73 60
Telefax: 046 - 222 46 12

Department of Fire Safety Engineering
and Systems Safety
Lund University
P.O. Box 118
SE-221 00 Lund
Sweden

brand@brand.lth.se
http://www.brand.lth.se/english

Telephone: +46 46 222 73 60
Fax: +46 46 222 46 12

## Sammanfattning

I takt med att konventionella landbaserade oljekällor och oljekällor på grunt vatten förbrukas utvinns olja allt oftare på djupt vatten. Med hjälp av nyutvecklad subsea-teknologi går det idag att utvinna olja och gas på upp till 3000 meters djup. Användandet av sådan teknik leder dock till nya risker som måste hanteras. Eftersom de flesta brett accepterade standarder och regelverk syftar till andra typer av processindustri, exempelvis topside-installationer, finns det ett behov av att nya riskhanteringsmetoder utvecklas. Subsea system skiljer sig från topside-installationer inte minst på grund av reducerad tillgänglighet.

Som ett steg i att möta detta behov har en modell för användandet av Layer of Protection Analysis (LOPA) för subsea-produktionssystem utvecklats. Modellens syfte är att analysera systemrisken, jämföra den mot satta riskacceptanskriterier och bestämma lämplig Safety Integrity Level (SIL) för alla instrumenterade säkerhetsfunktioner. Om det visar sig att systemrisken överstiger den acceptabla risken så måste befintliga säkerhetsbarriärer förbättras eller så måste ytterligare säkerhetsbarriärer adderas.

Modellen är skapad för att kunna användas i ett globalt perspektiv, vilket innebär att modellen inte är avgränsad till några specifika geografiska områden eller omständigheter. Modellen skall kunna anpassas till olika förhållanden endast genom att ändra på vissa variabler. Vidare är modellen är semi-kvantitativ till sin natur. Med detta menas att den baseras på en kombination av statistisk data, expertbedömningar och logiska resonemang. Det är viktigt att förstå att modellen i sig själv inte avser leverera ett korrekt svar på frågan om lämplig SIL-klassning men däremot erbjuda ett ramverk inom vilken LOPA-expertgruppen kan agera för att avgöra detta.

Valideringen av modellen visar att resultatet är rimligt med avseende på som är ekonomiskt och teknologiskt möjligt. Vid utvärderandet av ett ”single sattelite well” subsea-system gav modellen SIL3 krav för den instrumenterade säkerhetsfunktionen ”isolering av oljebrunn”, men lägre krav för mindre kritiska säkerhetsfunktioner. Det ter sig rimligt med tanke på att funktionen för ”isolering av oljebrunn” är den säkerhetsfunktion som agerar närmast själva oljekällan. I och med detta så skyddas hela subsea-systemet, vilket inte hade varit fallet om höga SIL-klassningar istället tillägnats andra instrumenterade säkerhetsfunktioner positionerade på längre avstånd från ursprungskällan.

## Summary

As the conventional oil reserves onshore and on shallow water are depleted, petroleum industry is advancing into deeper water at an increasing pace. Yet, new subsea technology has made it possible to extract oil at up to 3000 meters depth. However, usage of such new technology also presents new risks, which have to be handled. Therefore, there is a need of new methods to be developed, since most widely accepted standards and regulations today are aimed at other applications than subsea.

This thesis intends to be a part of meeting that need by the development of a model for application of Layer of Protection Analysis (LOPA) for subsea production systems.
The models main objective is to evaluate subsea production system risk, compare it with risk acceptance criteria and to determine the appropriate Safety Integrity Level (SIL) for all Safety Instrumented Functions (SIF). If the subsea system safety requirements are not met, present protection layers have to be improved or additional protection layers have to be added.

The LOPA-model is created in order to be useful in a global perspective, which means that the model is not limited to any specific geographical locations and/or specific conditions. The model can be adapted to various conditions simply by changing specific input parameters. Furthermore, the model is semi-quantitative in its nature, which means that it is based on a combination of generic statistic data, expert judgement and logical reasoning. It is important to understand that the purpose of this thesis is not to deliver the correct answer but to provide a framework in which the LOPA expert group can act.

According to the model validation, the result seems to be credible due to what is economically and technically feasible. For example, when evaluating a single satellite well subsea system it ended up with SIL3 requirement for the “isolation of subsea well function” but lower SIL requirements for other less critical Safety Instrumented Functions (SIF). It seems credible since the “isolation of well function” is closely located to the hydrocarbon source and therefore protects the overall subsea system. That would not have been the case with other SIFs.

## Acknowledgements

This master thesis was written during the summer and autumn in 2013 and is the final thesis in the master's programme in Risk Management and Safety Engineering at the department of Fire safety engineering and System Safety at Lund University.

The author would like to thank the following people for valuable guidance during the writing of this thesis.

| | |
|---|---|
| Anders Jacobsson | - *Academic supervision* |
| Kurt Petersen | - *Examination* |
| | |
| Thomas Solberg Fylking | - *External supervision at Oilconx Risk Solution* |
| Jorge Martires | - *External supervision at Oilconx Risk Solution* |

Lund 2013
*Christoffer Clarin*

## Abbreviations

| Abbreviation | Description |
|---|---|
| BOSCEM | Basic Oil Spill Cost Estimation Model |
| BPCS | Basic Process Control System |
| CBA | Cost Benefit Analysis |
| CRAC | Commercial Risk Acceptance Criteria |
| DHSV | Down Hole Safety Valve |
| ESDV | Emergency Shutdown Valve |
| EPA | Environment Protection Agency |
| EPD | Earnings per Day |
| EPU | Electrical Power Unit |
| ERAC | Environmental Risk Acceptance Criteria |
| FMECA | Failure Mode Effects and Criticality Analysis |
| GoM | Gulf of Mexico |
| HAZOP | Hazard and Operability Analysis |
| HIPPS | High Integrity Pressure Protection System |
| HPLP | High Pressure Low Pressure |
| HPU | Hydraulic Power Unit |
| HSE | UK Health and Safety Executive |
| IEL | Intermediate Event Likelihood |
| IPL | Independent Protection Layer |
| LOPA | Layer of protection analysis |
| PC | Production Cost per Day |
| PFD | Probability of Failure on Demand |
| PGB | Production Guide Base |
| PL | Protection Layer |
| PMV | Production Master Valve |
| PWV | Production Wing Valve |
| QRA | Quantitative Risk Analysis |
| ROV | Remote Operated Vehicle |
| RR | The needs of Risk Reduction |
| SCSSV | Surface controlled subsurface safety valve (DHSV) |
| SW | Swab Valve |
| SIF | Safety Instrumented Function |
| SIL | Safety Integrity Level |
| SIS | Safety Instrumented System |
| SPS | Subsea Production System |
| SSIV | Subsea Isolation Valve |
| TEV | Total measurable economic value |
| TGB | Temporary Guide Base |
| TMEL | Target Mitigated Event Likelihood |
| VSL | Value of a statistical life |
| WTA | Willingness to Accept |
| WTP | Willingness to Pay |
| XMT | Xmas tree |

## Table of Contents

# 1 Introduction

This master thesis is a part of the master's programme in Risk Management and Safety Engineering at the Faculty of Engineering, Lund University. It is written in cooperation with ORS, Oilconx Risk Solution. This chapter gives an introduction of the thesis, including background, aim, scope of work, limitations, assumptions and a description of the thesis structure. There is also an introduction to essential concepts important for the understanding of the thesis, such as safety barriers, Safety Instrumented System (SIS) lifecycle, Probability of Failure on Demand (PFD) and Safety Integrity Level (SIL). Finally, a short introduction of the analytical tool LOPA, Layer of Protection Analysis, and other risk analysis methods, as well as different present safety regulations, are described.

## 1.1 Background

Today depletion of onshore and shallow water reserves in combination with new technology has made remote controlled subsea systems capable of extracting oil at water depth up to 3000 meters. Unfortunately, with new technology new risk arises. In this thesis, risk is defined as a combination of the probability of a hazardous event and its consequences.

When constructing and operating subsea systems technical risk management is one of the most important aspects. Failure of a subsea system can lead to fatalities or devastating environmental and commercial consequences. The risks can be handled by mechanical, and/or electrical and/or mitigation systems or by construction measures, such as usage of an inherently safe design. However, most widely accepted international standards and regulations are aimed at other applications, such as topside installations, and not directly for subsea systems. These subsea facilities differ from topside installation not least though reduced accessibility. The available knowledge for evaluating subsea applications is therefore a need of new methods to be developed, as shown in Figure 1. This thesis is supposed to be a part of filling that gap.

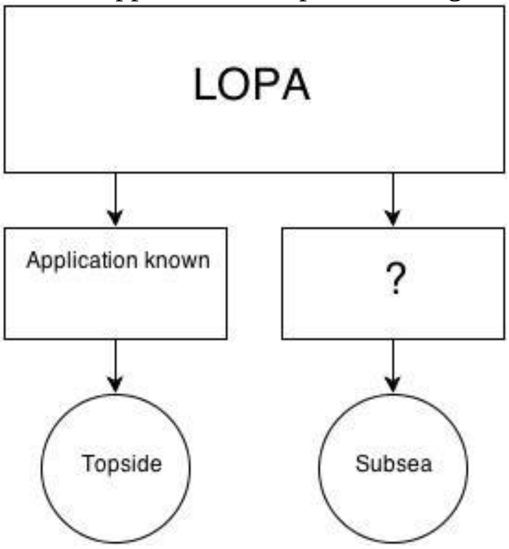


**Figure 1 This thesis is intended to describe how to apply LOPA in subsea context.**

## 1.2 Aim

The purpose of this thesis is to develop a method for applying LOPA, Layer of Protection Analysis, in order to determine target safety-, commercial- and environmental Integrity levels for subsea production systems. The developed model is made global. In other words, the model is supposed to work at any geographical location in the world by simply changing specific input parameters. The model could be used as a standardized way of evaluating subsea systems and by that decrease subjectivity within future evaluations.

## 1.3 Scope of Work

The scope of work covers the subsea part of the production facility, which stretches from the oil well to the beginning of the topside installation. Only wet tree systems are considered as subsea systems. This thesis comprises normal production phase and covers several subsea field layouts. The geographical circumstances are handled with input parameters which are changed due to the surroundings. Furthermore, the scope of work are limited to the LOPA part of the SIS lifecycle, which comprises Initial concept and design.

The subsea system risk can be compared with two "tolerable risk criteria". First of all, there are quantitative risk acceptance criteria based on frequency and consequence. If the system risk is considered too high, protection layers (PLs) can be used in order to decrease system risk so that acceptable risk limits are not being exceeded. Secondly, the thesis also provides an economic model, which makes it possible to estimate the correct safety integrity level out of a cost-benefit perspective. The Cost-Benefit Analysis (CBA) can be used for managing a proper balance between safety measures and the need of effective production. However, since the CBA-model tends not to favour high rated SIFs, the model shall only be used as a complementary method. Since the CBA is not considered as the main SIL-determination alternative, it is further described in appendix B.

The Thesis can be divided into the following parts:

- An introduction of the purpose and the project aims;
- Description of the system, including the whole subsea production system and its subsea units;
- Identification of subsea hazards and the initiating causes regarding environmental-, safety- and commercial impact;
- Quantitative risk acceptance criteria are created due to environmental, commercial and safety impact;
- Identification of safeguards and Independent Protection Layers (IPLs) suitable in subsea context;
- The system risk is determined by combining the system release frequency by the consequences of a release.
- A description of how system risk can be compared with risk acceptance criteria is made. Equations are presented so that the SIFs SIL requirements can be set in order to reach acceptable risk limits;
- Discussion and conclusions.
- Creation of a hypothetical system and validation of the model;
- A Cost Benefit Analysis (CBA) is created. A Cost Benefit Analysis (CBA) is presented in order to measure damage in monetary terms and to determine necessary safety requirements.

As opposed to a standard LOPA, based on generic initiating cause frequencies, this model takes basis in a generic leak frequency, i.e. the frequency of an events consequence. In order to adjust the generic frequency into a specific subsea system, several correction factors based on engineering judgement are being used.

## 1.4 Limitations and assumptions

During the hazard- and initiating event identification, the following assumptions regarding system design were made:

- The design pressure of the Xmas tree is above full reservoir pressure;
- The design pressure of chemical injection service line and annulus is above full reservoir pressure;

- The subsea system has an inherently safe design due to expected temperatures of oil, water and injected chemicals. The design shall prevent damage due to overpressure or material degradation;
- No corrosion or material degradation occurs due to chemical incompatibility;
- Pipelines, flowlines and riser installations are built according to international standards;
- Maintenance work is properly performed according to international standards.

Several initiating causes were identified. However, failure frequency data for each initiating cause could not be found. Therefore, all initiating causes have as much as possible been merged into seven failure categories for which the failure fraction is known.

When the base frequency was estimated, generic data from known sources, such as OREDA (2009), were used. Operator experience is usually a better source for specific events, but generic industry failure rate data are better when it comes to overall equipment failure, due to more significant statistic /6/. The failure frequencies were estimated according to the following assumptions:

- The failure mode was limited to include leakages;
- Only releases of hydrocarbons inside the safety zone are assumed to be a safety issue. Releases in open sea are assumed to only cause environmental and commercial impact;
- The oil spill duration time is assumed to be a function of maintenance time and a time-dependant correction factor.
- The same maintenance time as needed for repairing critical leakages on wellheads and manifolds is set for broken manifold connectors, since no other data was available.
- Flowlines and jumpers are assumed to have the same failure frequency as pipelines.

The quantitative risk acceptance criteria are divided into three parts, environmental-, safety- and commercial risk acceptance criteria. In all three cases a linear relationship is assumed, e.g. the allowed frequency of a 100 000 tonnes oil release is ten times less than for a 10 000 tonnes oil release etcetera. Further assumptions are listed below:

- Target Mitigated Event Likelihood (TMEL)
  TMEL is based on the common safety industrial praxis of one tolerable fatality in 10 000 years. Furthermore, one permanent injury is assumed to be ten times less severe, and one recoverable injury 100 times less severe, than on fatality
- Environmental Risk Acceptance Criteria (ERAC)
  The ERAC depends on the hazardous event frequency and the quantity of the hydrocarbon release. The acceptable frequency for a hazardous release of 10 000 tonnes of oil is set to one in 100 000 years, which is the same as the acceptable frequency industrial praxis for a topside catastrophic events.
- Commercial Risk Acceptance Criteria (CRAC)
  The CRAC is based on the qualitative judgement of big oil producers. In order to estimate how often an event with a specific commercial impact occurs, the impact cost was assumed to be correlated to the oil spill amount and the region where the oil spill occurs.

The CBA is based on the frequency of an event, the cost of the safety measures and the consequences measured in monetary terms. The consequences are divided as following:

- Environmental impact: Environmental impact is defined as a combination of non-market values, such as clean water and recreation activities, and market values such as lost income for fisheries and tourism businesses.
- Commercial impact: Commercial impact is limited to operational clean-up costs and loss of production. Third party claims is assumed to be included into the environmental impact evaluation, since claims are often based on those losses.
- Safety impact: Safety impact comprises the number of fatalities and the value of a statistical life.

Since the CBA is not considered as the main alternative when to determine system safety requirements, but well as a complementary method which can be used in order to find a proper balance between safety measures and production, the model is further described in appendix B.

## 1.5 Project structure

This thesis is divided into eight chapters and four appendixes. In this section, all these parts are given a short description in order to give the reader a clear picture of the overall scope of work. Figure 2 shows an overall picture of the thesis structure.

*Chapter 1:* The first chapter begins with an introduction of the project, including background, aim, scope of work, limitations and made assumptions.This part contribute to the reader's understanding of why the project is implemented and what to accomplish. The chapter also comprises some essential concepts which are important for the reader's further understanding.

*Chapter 2:* The second chapter comprises a system description which provides an introduction to the oil and gas industry, subsea system units and subsea system layouts. The chapter provides the necessary technical knowledge for understanding further reading.

*Chapter 3:* The next chapter comprises a hazard- and initiating cause identification. In this thesis, a hazard is defined as a hydrocarbon release causing environmental, commercial and/or safety impact. The initiating causes are those events that enable a hazard to be developed, for example corrosive environment, dropped objects or extreme weather conditions.

*Chapter 4:* The fourth chapter is about adapting a system specific base failure frequency, based on the subsea system design and generic data for different subsea units. The generic data is average in nature and do not take any specific circumstances into account. However, the specific base failure frequency provides a good base failure rate estimate, able to modify in order to better reflect reality.

*Chapter 5:* The fifth chapter is about defining acceptable risk criteria. In this thesis, there are three different criteria, ERAC, TMEL and CRAC. These acceptance criteria shall be considered as lower boundaries, i.e. the specific subsea system risk is not allowed to exceed these bounds.

*Chapter 6:* Protection layers are important tools in order to reduce the overall subsea system risk. In chapter 6, the protection layers suitable for subsea systems are identified and described. When possible, the protection layer PFD or LOPA credit is estimated.

*Chapter 7:* Chapter 7 provides a full description of the developed LOPA-method, which comprises a subsea system risk assessment and a SIL-determination process. Since risk is defined as a combination of frequency and consequence, the base failure frequency is modified in order to take specific risk affecting conditions and protection layers credit into account. The environmental and commercial consequences are estimated by calculating the quantity of an oil release, while the safety related risk are calculated by combining qualitative estimates and system specific frequencies. If the total system risk is considered too high, a SIL rated safety functions have to be added or the system design have to be changed. The appropriate SIL is determined by comparing the specific subsea system risk with the risk acceptance criteria.

*Chapter 8:* The master thesis ends with a discussion about the developed model. It comprises a discussion about the model advantages and weaknesses, the model uncertainties and what can be improved in future work.

*Chapter 9:* This chapter provides the references used during this master thesis.

*Appendix A:* In Appendix A, the model is validated by a calculated example. It is an important step in ensuring that the developed method actually works as intended. The chapter can also be used as a user guideline, since all calculations made are clearly described.

*Appendix B:* In Appendix A, a CBA method is presented in order to find the most cost effective balance between safety measures and risk. Firstly, the subsea system average event consequence is measured in monetary terms. The monetary loss refers to environmental impact, commercial losses and fatalities. All these three terms can be summarized in order to find out the overall cost of an accident. Secondly, the average cost of an accident is compared with the cost of additional safety measures. The method can be used in order to find the most cost effective balance between safety measures and risk.

*Appendix C*: Appendix C provides an overview of different offshore platforms. These structures are beyond the subsea system boundaries, but are an important part of the overall production system.

*Appendix D*: This Appendix provides parts from the HAZOP report which was studied during the hazard and initiating cause identification.

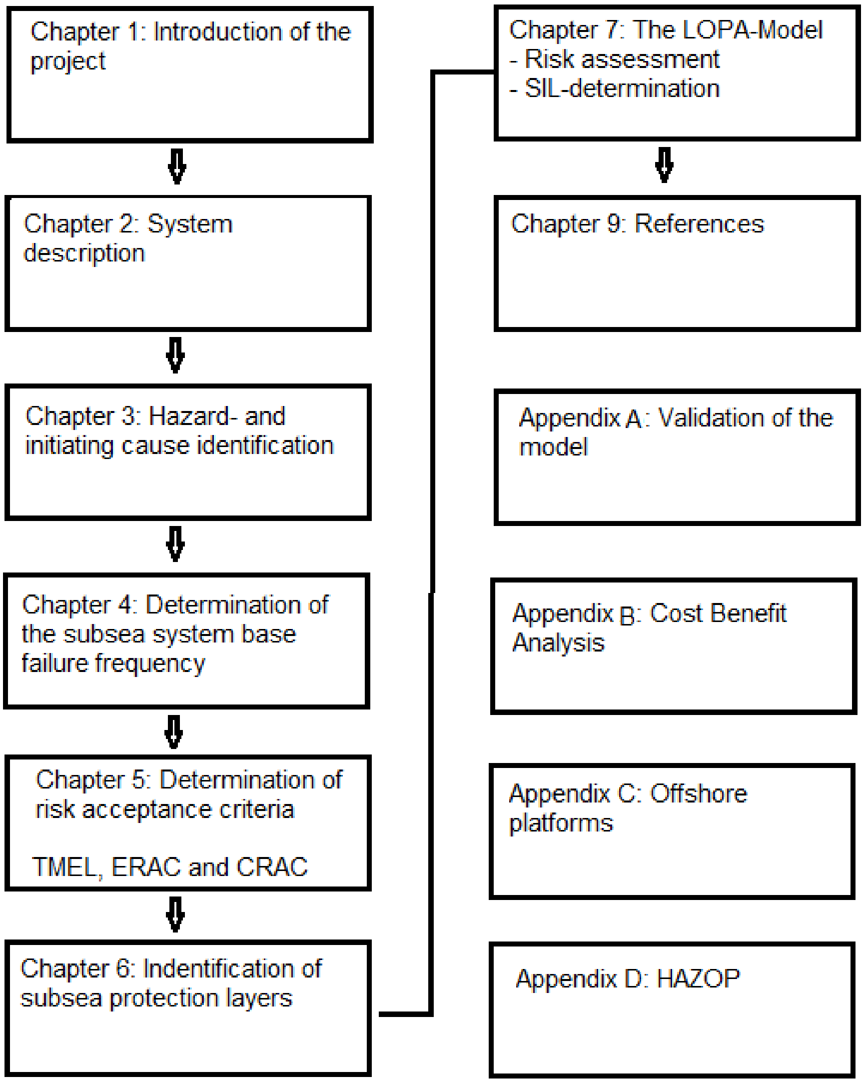


**Figure 2 shows the thesis structure**

## 1.6 Independent protection layers and SIL-classification

When to assess the process risk it is important to look at the overall design. If the risk is considered as unacceptable there are needs of safeguard enhancement. A safeguard is any device, system or action that interrupts a chain of events leading to consequences or mitigates its consequences. It may comprise process design, control systems, prevention and mitigation equipment, physical barriers, training and certification, maintenance, communication equipment and emergency response, as shown in figure 3. Safeguards reduce risk by elimination, detection and control, mitigation or by handling the consequences after they have occurred. Eliminating risks by using inherent design is often considered the best option while emergency response is usually considered as the last barrier of defence.

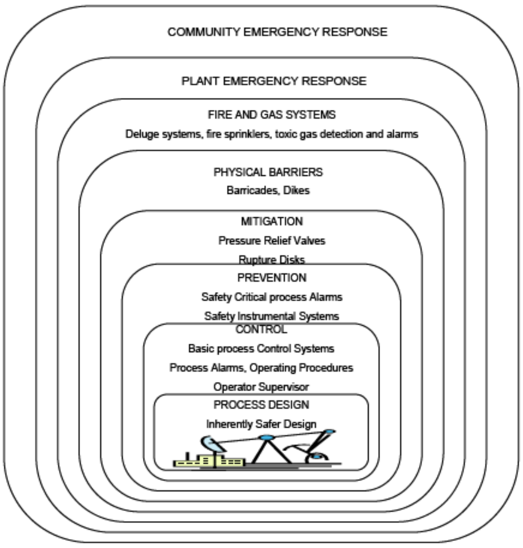


**Figure 3 Show safeguards in Oil&Gas Industry (From a big oil producers LOPA guideline)**

Some safeguards are defined as Independent Protection Layers (IPLs). An IPL is a device or a system capable of preventing a scenario to develop into an undesired consequence. Not all safeguards are IPLs, but all IPLs are considered as safeguards. To be qualified as an IPL it has to meet the following requirements /6/:

- Effective: The protection layers have to provide a minimum of a 10-fold risk reduction and the protective functions shall have a high degree of availability, more than 90 %.
- Independent: The protection layers have to be independent so that failure of another protection layer will not have any negative effect at the protection layer function.
- Auditable: The assumed effectiveness must be capable of validation, for instance by testing, documentation, review etcetera.

The effectiveness of an IPL is quantified in terms of its Probability of Failure on Demand (PFD), and may be termed as the risk reduction factor. Demand means that something runs out of control and a dangerous situation can arise. The PFD is simply the probability that the protection layer, when demanded, will not perform as intended. The PFD adopts a value in range zero to one. Consistently, a smaller value means a smaller probability of failure. The value is intended to take all potential failures and danger modes into account.

An IPL may be a Safety Instrumented System (SIS), which is a combination of sensors, logic servers and final elements. A SIS consists of a number of Safety Instrumented Functions (SIFs), which are state control functions. Each SIF has a PFD value depending on type, number of instruments and the interval between functional tests. The PFD increases with time, but it is assumed to be restored after a maintenance procedure. International standards, such as IEC 61508, IEC 61511 and OLF 070, have grouped the PFDs into categories called Safety Integrity Levels (SILs) /6/.These definitions are shown in Table 1 /45/. Note that SIL 4 only exists in theory and not used in practice.

**Table 1 Safety Integrity Level /45/**

| Safety Integrity Level | Probability of Failure on Demand | Risk Reduction |
|---|---|---|
| 1 | $1 \cdot 10^{-1}$ to $1 \cdot 10^{-2}$ | 10 to 100 |
| 2 | $1 \cdot 10^{-2}$ to $1 \cdot 10^{-3}$ | 100 to 1000 |
| 3 | $1 \cdot 10^{-3}$ to $1 \cdot 10^{-4}$ | 1000 to 10 000 |
| 4 | $1 \cdot 10^{-4}$ to $1 \cdot 10^{-5}$ | 10 000 to 100 000 |

## 1.7 SIS Lifecycle

The SIS lifecycle approach is an engineering process in order to optimize SIS design and preserve its risk reduction properties. It means that engineers should stay involved the whole life of the safety system so that all activities affecting the SIS function is carried out in the right time and in a correct way. The approach requires that everyone involved is competent to achieve their role /26/. The SIS lifecycle includes seven phases, specification, design, integration, operation, maintenance, modification and decommissioning, as described in figure and listed below /4/45/.

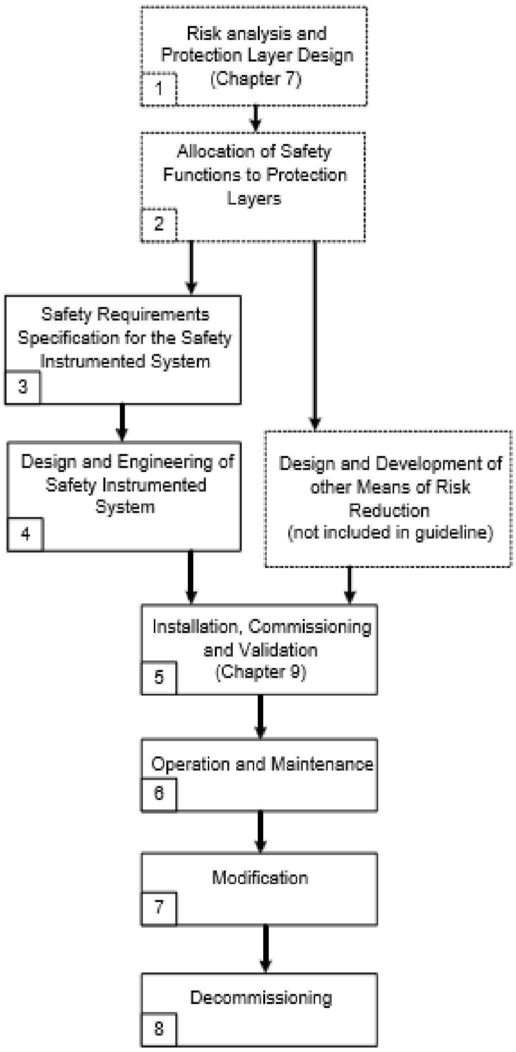


**Figure 4 the SIS Lifecycle process /27/.**

1. When using a SIS lifecycle approach a hazard and risk assessment has to be made. All events and sequences leading to a hazardous consequence shall be identified. This step also includes risk reduction requirements and which SIF that are needed /27/.

2. The next step includes further description of each SIF and the associated safety integrity level. For determination of SIL the LOPA method can advantageously be used /26/. LOPA is further described in the section 1.8.

3. Step three provides a Safety requirement Specification (SRS), which specify the requirement of each SIS, i.e. the software safety requirements and the reliability data for each part of the loop. The SRS report shall provide a basis for the safety loop design /26,27/.

4. The fourth step handles design of a specific SIS, which includes taking safety requirements and software requirements into account. It also includes planning for the SIS integration tests which shall be performed in the following step of the lifecycle process /27/.

5. The fifth step includes installation, commissioning and validation of the SIS. It is made in order to validate that the SIS meets all requirements, with respect to the required SIL. The step results in a fully functioning SIS in conformance with specified SIS design results.

6. SIS operation and maintenance is performed in order to ensure that the SIS safety requirements are provided over time. The reliability and effectiveness of all layers of protection needs to be monitored so that the SIL rating from the original assessment can be adjusted to the reality /26,27/.

7. Any change to any of the layers of protection affect the reliability demands that rests upon the SIL rated functions. Therefore, the safety instrumented systems needs to be reassessed so that the total risk reduction requirement is met over time /26/.

8. Finally, when it is time decommissioning, it is important to ensure that proper review, sector organization and the total system risk remains at an appropriate level /27/.

## 1.8 Overview of LOPA

Layer of Protection Analysis (LOPA) is an analytical tool to determine if there are sufficient layers of protection against a hazardous scenario. Usually many types of protection layers can be applied, but only one protection layer has to work successfully to prevent the consequence. However, no protection layer can be 100 % reliable and an analysis has to be made to ensure system tolerable risk level. If the risk is not tolerable, additional safety measures have to be added. LOPA only judge whether there are sufficient protection or not and does not suggest which type of protection to be added. LOPA simply help the analyst to decide how much the system risk has to be reduced in order to reach tolerable risk level. LOPA can be divided into different steps /6/.

What LOPA actually do is first of all an initiating event frequency identification and estimation of failure of all layers of protection. When multiplying these factors, the result is the frequency of a hazardous outcome. If the result is considered at the wrong side of the acceptable risk criteria, safety measures have to be made to fill that gap, called the residual risk. The engineers can choose to go back and enhance the design, improve any of the already existing layers of protection or decide to install a new SIL rated Safety Instrumented Function (SIF) /26/. The process is shown in Figure 5.

The method does not automatically decide if there is a need of a SIL rated safety function. If the system risk is near the tolerable acceptance criteria, it may be enough to just improve the already present layers of protection. A SIL rated high reliability safety function is expensive to design, expensive to buy, expensive to install and expensive to validate. The need of a SIL rated safety loop should therefore be seen as a failure rather than a success. The best offshore installation is these with an inherently safe design without any need of safety functions. The SIL rated safety functions are not intended to be a sticky plaster over poor process design /26/.

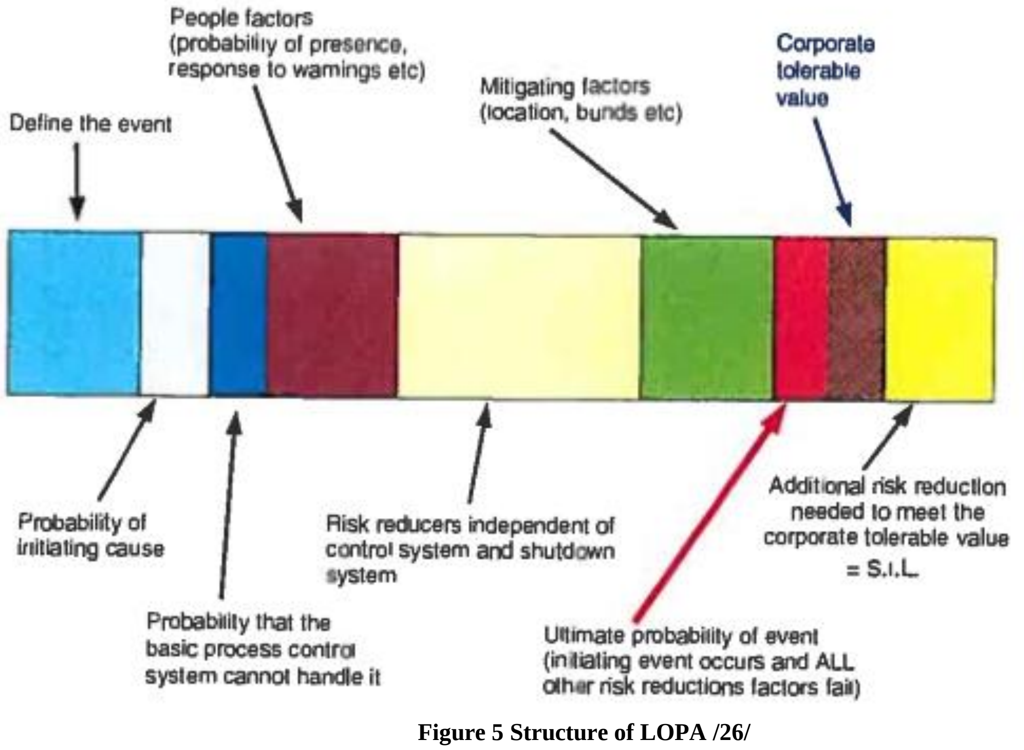


**Figure 5 Structure of LOPA /26/**

LOPA requires less effort than a Quantitative Risk Analysis (QRA), and is an appropriate model to use if the system is too complex for using only qualitative judgement. For simple decisions, the value of LOPA is minimal. However, the method may also be over simplistic for very complex systems. LOPA performance can be divided into following steps /6/.

*Step1. Identify the consequences.* The first step is to screen scenarios and to decide which consequences to avoid. Some companies stop at the magnitude of an unwanted release, while others explicitly estimate the risks by addressing the consequences.

*Step2. Select an accident scenario.* LOPA is applied at one scenario at a time. Scenarios are identified during an identification procedure where all events leading to a specific consequence are determined. The analysis describes the identified events as single cause-consequence happening. The scenarios are usually identified by qualitative risk assessment methods such as HAZOP or HAZID.

*Step3. Identify the initiating event of the scenario and determine the event frequency.*
In this step the frequency of a consequence, given failure of all IPLs/Safeguards, is determined. The frequency has to be based on the background of the scenario, like how often an operation causing an event is actually exercised.

*Step4, Identify IPLs and estimate its probability of failure on demand.* Depending on the scenario and the system properties there can be different kinds of IPLs. Some accident scenarios need many IPLs while other needs one or none. An IPL can be high rated or low rated depending on its effectiveness to prevent an event to develop into an unwanted consequence or to mitigate the consequence. The effectiveness of the IPL or safeguard is quantified as probability of failure on demand (PFD).

*Step5. Estimate the risk of the scenario.* In LOPA, the risk of a scenario is defined as the consequence multiplied by the frequency. All IPL data lowering the risk should be taken into account. In other words, the total risk is a combination of the consequence and the frequency of an event and the IPLs affecting these factors. The risk is not allowed to exceed specific tolerable risk criteria, e.g. TMEL.

*Step6. Evaluate the risk to reach a decision concerning the scenario.* The final step includes comparison between the acceptable risk criteria and the total risk of the scenario. The results can be used to identify which safety measure to focus on. If the residual risk is low, simple design enhancement may be enough. Otherwise, extra SIL rated safety function can be added. Figure 6 show a comparison between LOPA and an event tree analysis and how each IPL reduces the frequency of an unwanted consequence.

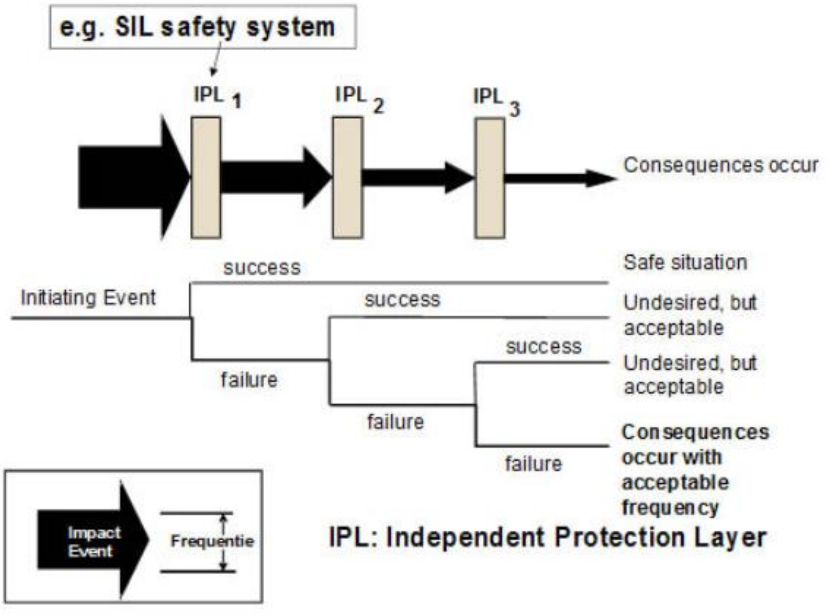


**Figure 6 Comparison of LOPA and event tree analysis /6/**

LOPA is not intended to be a hazard identification tool. For that purpose, qualitative methods such as HAZOP can be appropriate. HAZOP results can advantageously be used as input into the LOPA process, so that the analyst can estimate the risk of each scenario in a consistent and simplified manner /6/. A schematic illustration of the LOPA process is shown in Figure 7 . The necessary risk reduction can be calculated by equation 1. IEL are the intermediate event likelihood of an event to occur when all IPLs are present. TMEL stands for target mitigated event likelihood and are the maximum frequency allowed for a specified consequence affecting humans. There are corresponding acceptance criteria for environmental and commercial risk acceptance criteria, ERAC respective CRAC.

(Equation 1) $$PFD_{SIF} = \frac{IEL_1+IEL_2+IEL_3+\ldots IEL_n}{\text{Acceptable risk (TMEL, CRAC or ERAC)}}$$

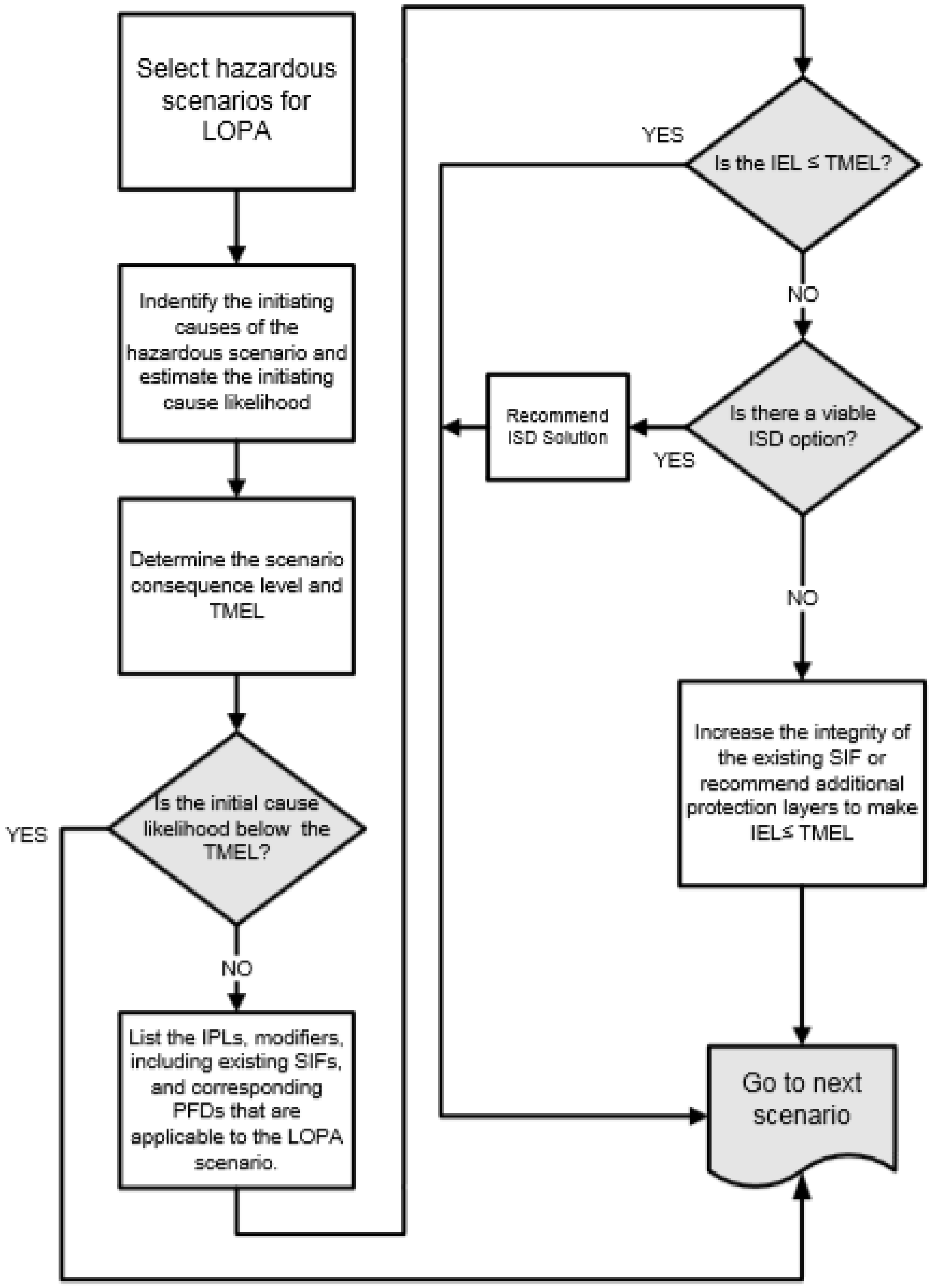


**Figure 7Schematics of LOPA (from a big oil producers LOPA guideline)**

## 1.9 Other risk assessment

There are many systematic ways to identify, analyse and respond to process risks. The purpose of all methods is to identify measures to minimize the consequence and/or the frequency of hazardous events. In some cases a rough and simplified model may be sufficient, but if complex systems are analysed more advanced methods have to be be used. The various methods can be based on qualitative judgements, semi-quantitative analysis or quantitative risk assessments. No method is "the best", it all depends on the circumstances, the system to be analysed and the time and resources available. Some of the most used methods are given a short review below.

*Design Review:* The method is used to evaluate the design based on expert opinion at various stages in the process. It may be used to identify weaknesses of the design for a whole system, structure or component /3/.

*FMECA:* Failure mode, effect, and critically analysis is a systematic tool used in order to identify, and if possible, design out failure modes. The method is applicable at all project stages but can be prioritized to areas of design weaknesses. The model is successfully used to identify needs of additional safety systems. The task may be performed by a single experienced person but is more often performed in group /19/. The weakness of the method is that it can be a time-consuming task and that the real reason of the failure is not fully identified /19/.

*HAZOP:* The Hazard and Operability Analysis process derives deviations in the process by utilizing keywords in a certain point of the process. When using the method there is a need of detailed information about the system and the task is usually performed in a group managed by a team leader. The method is all qualitative and is usually used at the design phase of a project /19/. HAZOP give meaningful deviations, i.e. accident scenarios, and list safeguards. The HAZOPs result can advantageously be used as input in further LOPA valuation /6/.

*Fault Tree Analysis:* Fault tree analysis is a potential system for assessing required SIL where common-mode failures exist. That is an advantage against LOPA which assume that all IPLs are 100 % independent, which is never completely true. The method also allows accurate assessments. However, it is not suited for team assessments as the logic itself needs experience to handle. The method may be all quantitative /26/.

*Risk Graph:* The risk graph is a semi quantitative method which can be used to estimate the probability of failure on demand for a loop. The method suits a team assessment assignment and, if the graph is correct mathematically calibrated, it can be used for SIL assessment. The method is time efficient but not as accurate as LOPA or fault tree analysis /26/. The method can be used for deciding which events to study in a LOPA process

*Risk Management Plan:* The plan includes resources, roles, responsibilities and schedules. By applying it at all phases of the project, risk can be reduced and decisions can be made with better understanding of the total risk picture /3/.

## 1.10 Standards and regulations

Effective management systems are needed to handle safety issues in all companies associated with the offshore oil and gas industry. Some key elements in management systems are hazard identification, risk assessment and introduction of risk reduction measures. These management systems should be applied to all stages of the life cycle of an installation and to all related activities /30/. Therefore, some widely accepted international standards provide regulations, best practice and recognition of particular circumstances. Some nations have also made national interpretation, such as the OLF 070 guideline in Norway. The relationship between these different offshore standards is shown in Figure 8 and a short description of each standard feature, linked to numbers in the figure, is listed below /30/:

1. Tools and techniques for systematic hazard identification and risk analysis;
2. Requirements for instrument systems used for sole or secondary protection;
3. Safety integrity requirements for fire and gas and emergency shutdown systems;
4. Requirements for fire and explosion strategy and support systems;
5. Requirements for instrument products used for safety that have not been proven by “prior use”.

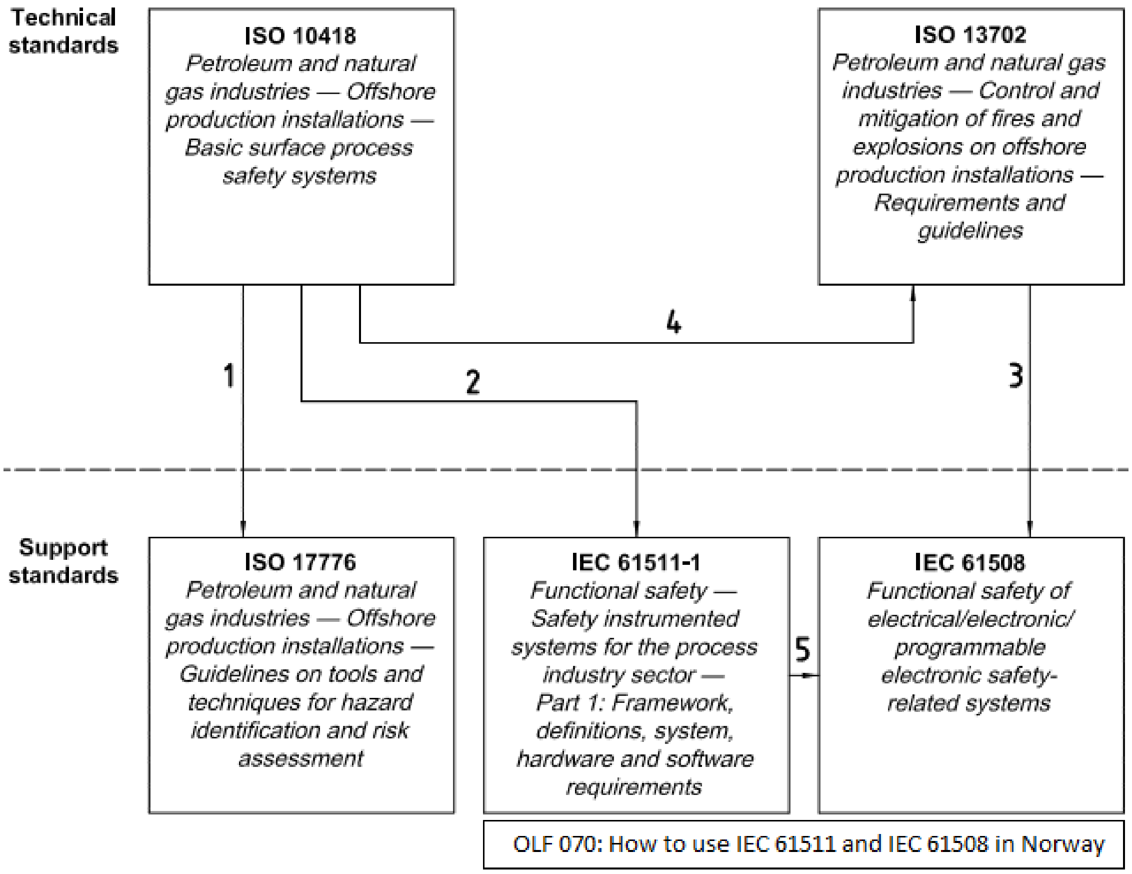


**Figure 8 Relationship between offshore-relevant standards /30/.**

SISs are widely used for avoiding major accidents by reducing the probability of an unwanted consequence to occur. The SISs are strictly governed by use of international standards and national guidelines, such as IEC 61508, IEC 61511 and OLF 070. Determination of required SIL for SISs is an important step in the SIS design process. However, these standards are aimed at other applications, such as topside installations, equipment suppliers and process industry, and not directly subsea production systems. Despite that, they can still comprise valuable information. A short description of the most used standards is as follows:

*IEC61508*

The IEC 61508 is an international standard providing a generic approach for all safety lifecycle phases, from initial concept through design, implementation, operation and maintenance to decommissioning, for safety systems comprised of electrical and/or programmable electronic components. The purpose is to provide a rational and consistent technical policy suitable for all electrically based safety-related systems. However, a guideline based on other technologies is presented as well. The broad acceptance of the standard has given suppliers and users a common framework when working with these applications. IEC 61508 can be seen as a generic standard mostly for manufacturers and suppliers of devices /28/.

*IEC 61511*

This international standard is a sector implementation of IEC 61508 addresses the application of safety instrumented systems for the process industries. SIS includes all components needed to carry out its function, from sensor to final element. IEC 61511 presents two main concepts, safety lifecycle and SIL, so that the SIS can be confidently entrusted and maintained in a safe state. The standard is divided in the following parts:

− Part 1: Framework, definitions, system, hardware and software requirements
− Part 2: Guidelines in the application of IEC 61511-1
− Part 3: Guidance for the determination of the required safety integrity levels

The last part provides information about the relationship of risk to safety integrity, methods for determination of tolerable risk and various methods for determine SIL. A guideline of how to use LOPA to select the required SIL is presented. The use of LOPA is not mandatory but recommended. IEC 61511 also enables existing country specific standards to be harmonized with this standard. The standard is mostly written for system designers, integrators and users /27/.

*OLF070*

The purpose of the OLF 070 is to issue a national guideline, including IEC 61508 and IEC 61511, in order to simplify the usage of these regulations in the Norwegian Petroleum Industry. The document does not provide a fully risk based approach but minimum SIL requirement for the most common safety functions due to risk to personnel. For some cases, such as particularly vulnerable environment, other requirements might be considered. The rationale is to enhance standardisation within the industry sector and avoid time consuming calculations on standard safety functions. OLF 070 also provides typical loop diagrams for a number of safety functions and component reliability data. One main objective of the OLF 070 is to ensure a safety performance level equal or better than other standards. Hence, when generic reliability data has been used between two SIL, the stricter has been chosen. Furthermore, the SIL must always fulfil the overall acceptable risk. Some recommended minimum SIL requirements mentioned in the guideline are:

- Subsea ESD, Isolation of one well – SIL 3
- Isolation of riser, shut in of one riser – SIL 2

When deviations are identified, a qualitative or quantitative risk based method to determine SIL can be used. Deviations can be with respect to consequences of an associated hazard, special consideration due to frequency of an event or a functional deviation such as replacing one safety system with another /45/.

# 2. System description

This system description will give a short summary of the oil industry leading up towards the complex subsea structures of today, as well as introducing some basic concepts within oil and gas production. The chapters aim is to give a motivation behind the development of methods for assessing risk related to the production of oil and gas, and the purpose and goal behind the evolution of standard layers of protection methodology to suit the risks to environment and asset inherent to today's complex subsea production structures.

## 2.1 History

The modern oil industry was created when Edwin drake, in year 1859, drilled the first successful onshore oil well in north-western Pennsylvania. The well was shallow by modern standards, only 24 meters, but could give quite a large production. This example became the origin of an industrial international search and industrial use of oil. The oil was initially collected and sold in wooden barrels, which has led to the today standardized unit barrel, 159 litres /8/.

During the first half of the $19^{th}$ century the oil consumption increased rapidly. The automobile industry adopted the fuel and gasoline engines soon proved to be essential for development of successful aircraft. After World War II the petrochemical industry, with its new materials and improved welding techniques, increased production even more /8/.

The first offshore oil well was constructed in 1947, when Kerr-McGee completed the first successful well at 4.6 meters water depth in the Gulf of Mexico (GoM). Today, depletion of onshore and shallow water reserves in combination with new technology has made the petroleum industry advancing into deeper water at an increasing pace. The concept of subsea fields, with wellhead and underwater production equipment on the sea bed, was developed in the early 1970. The technique has constantly been evolving since then. During the past 40 years the concept of subsea systems has improved from being shallow water manually operated systems to advanced remote controlled systems capable of extracting oil at water depth up to 3000 meters. The subsea systems have particular demands on engineering due to inaccessibility of installation, operation and maintenance /3/. Nowadays, fossil fuels amount for 80 % of the world energy consumption, despite new innovations and renewable energy sources. Of the fossil fuels consumed, 80 % is oil and gas /3/.

## 2.2 Threats from Oil Spills – General trends

A decade ago, oil spills from tankers was the dominating source of oil releases. Since then, the accident rate has decreased significantly due to modern tankers with double hulls, sectioned storages, establishment of sea lanes and use of GPS. However, pipeline ruptures and leakages show an opposite trend. The number of marine spills has increased from an average of 47 accidents per year in the 1960s and 70s to about 350 during the first decade of this millennium. Increased total length of pipelines, ageing equipment, insufficient maintenance, corrosive conditions and pipelines becoming military targets are some of the main reasons /34/.

Considering marine blowouts there are no clear trend line. It has been a period with few large releases from the late 1980s to late 2000s, with larger releases in the period of time before and after. A blowout is an incident where formation fluid flows out of the well after all protection layers have failed. Blowouts on land and in shallow water can relatively easy be handled and they seldom lead to large releases. On the other hand, if the blowout appears at deep water the wells are harder to cap, due to difficult accessibility, resulting in large releases and severe consequences.

During the last 30-40 years safety equipment has improved tremendously, but the oil companies have also moved into even deeper water and into stormier and icier seas. The risk potential and the safety related challenges have therefore also grown. Table 2 show the worst marine blowouts in history. The Deepwater Horizon accident will possibly be added at the very top of the table/34/.

**Table 2 Show some of the largest marine blowouts in history /34/**

| Well | Country | Year | Tons spilled | Comment |
|---|---|---|---|---|
| Ixtoc I | Mexico | 1979 | 475 000 | |
| Nowruz | Iran | 1983-1985 | 100 000 | After attack by Iraqi airplanes |
| Nowruz | Iran | 1983 | 40 000 | After oil platform was hit by a tanker |
| Ecofisk | Norway | 1977 | 27 000 | |
| Funiwa 5 | Nigeria | 1980 | 26 000 | |
| Montara | Australia | 2009 | 20 000 | |

When it comes to leaking pipelines the large scale releases are seldom reported, leading to inaccurate statistics. However, some large oil spill from former Soviet Union has been reported. In 1988 a pipeline burst and fire caused a spill of 20 000 tons of oil, in two incidences in 1992 almost 30 000 tonnes of oil leaked out and in 1994, near the town Usinsk, a pipeline was leaking for more than half a year leading to a 100 000 tons release /34/.

## 2.3 Environmental impact of oil spills

A large scale release of hydrocarbons may cause severe environmental damage. Several factors affect the outcome, such as quantity of the release, type of oil, which time of the year it happens and where it happens. Likewise, temperature and water turbulence will be of great importance /34/.

The type of oil matters due to differences in toxicity and natural degradation. Lighter components like gasoline and diesel evaporate unlike heavy oil which tends to affect the environment during a longer period of time. On the other hand, many light products can cause acute toxic effect to living organisms /50/.

An oil spill near the surface spreads out in a thin layer. Water-soluble components dissolve in the water creating an emulsion with brownish colour. It means that the oil breaks up into small droplets and mixes with the surrounding water due to turbulence and wave actions. The suspended oil droplets are then attacked by specific bacteria and biodegradable components are being consumed. UV-radiation from sunlight also helps to break down some of the oil components. Fractions that are resistant to both sunlight and bacteria, like asphaltenes, are accumulated in sediments and/or on beaches /34/.

If the oil spill occurs due to a blowout from a deep water installation, the hydrocarbons will be mixed with sea water under high pressure. A three-phase emulsion, also including sand and mineral particles, will thereby occur. The emulsion will have different densities varying over time due to composition changes. Thus, it can form underwater clouds that ride on density gradient, impossible to notice from the surface /34/.

On sea surface and beaches heavy oil has more damage potential to birds and mammals due to its stickiness. The oil smothers mammals like birds and seals, decreasing their normal insulation capacity and water resistant features. Just small stains are enough to cause hypothermia in cold water /51/. Light oil is more able to mix into water causing harm to crabs, mussels and other sea living animals instead. The use of dispersants to speed up the biodegradation is one way of protecting birds and mammals near shore, but it also increases the exposure to sea living creatures /22,34/. Fishes living beneath the surface are usually able to avoid oil in the water and are seldom affected. However, if the spill is near shore in shallow water, important for spawning, the consequences can be devastating /3/.

Generally, the immediate toxic effects are higher in warm water, but so are also the biodegradation. A thumb rule is that the degradation process doubles for every 10°C. Therefore, biological impact is generally higher in cold and arctic water. Experience from the Exxon Valdez disaster, and other cold water accidents, shows that ecosystems along rocky coasts is often restored after about two years, while it usually takes up 4-6 years for more sensitive coast lines. However, ecosystems may also suffer permanent damage. For instance, large bird populations in small areas may never completely recover /52, 34/.

## 2.4 The hydrocarbons

There are two main theories of were petroleum come from. The inorganic theory states that oil is the result of chemical reactions of different minerals. Even though scientist has found out that minerals can be transformed into oil, it seems that most of the oil is derived according to the organic theory. The organic theory means that oil is the remaining out of organic material, such as plankton and algae, which has been buried by layers of sand and silt and transformed into hydrocarbon during millions of years /47/.

Crude oil can vary significantly in colour and viscosity, from clear to black and from watery to almost solid. Its uses varies, from asphalt and waxes to plastic and gasoline /23/. Crude consists of a mixture of up to 200 different organic compounds of mostly coal and oxygen. The compounds differ in size and complexity and are separated though a refinery process. Crude from different fields can be either dissimilar or similar in its composition. Crude oil density typically ranges at approximately 970kg/$m^3$ to 750kg/$m^3$, which means that most crude floats on water /8/. The classification of crude oil is illustrated in figure 9.

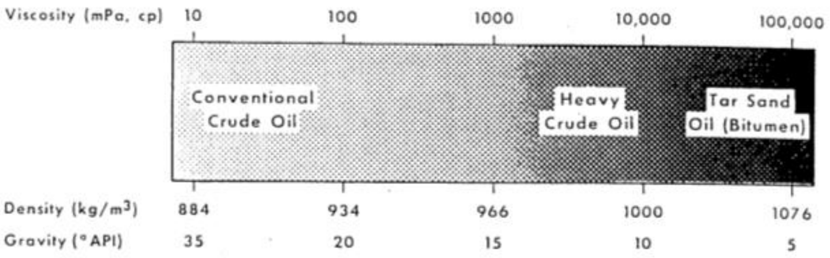


**Figure 9 classification of crude oil /55/.**

Natural gas used by consumers consists almost entirely of methane, but raw natural gas is not entirely pure even though it constitutes the majority of the content. Raw natural gas also contains hydrocarbons such as ethane, propane, butane and pentane and other gases like water vapour, hydrogen sulphide, carbon dioxide and nitrogen. The gas can be found dissolved in oil or as free gas. If the natural gas is extracted from an oil well it is called an associated gas, otherwise it is called non-associated gas. The different compounds of the gas are separated into pipeline quality dry natural gas or condensates. Condensates are all other gases than methane, and can be used as a source of energy, enhancing recovery in oil wells or as a diluent for heavy crude oil /8/.

The hydrocarbon composition makes them highly flammable. The substances can cause explosions or cause uncontrolled fires, leading to fatalities, structural damage or loss of asset. The substances also have a toxic effect, causing harm to living creatures and environment. It is therefore of major importance that the production is safely managed.

## 2.5 Reservoirs

An oil reservoir is formed when hydrocarbons, created in the source rock deep underground, starts to migrate towards the surface due to buoyancy, pressure and/or density difference between oil and water. The migration continues until it hits a trap, which enable the oil to accumulate in reservoir rock. The trap, which stops the migration and prevents the hydrocarbons from leaking out of the reservoir, is usually made of a non-porous layer such as salt, shale, chalk, or mud rock. The trap has to be a complete closure to make sure that oil does not migrate around it. In the reservoir, the gas will be accumulated on top, oil in the middle and water at the bottom, causing a gas-oil contact line and an oil-water contact line. These lines affect how oil will flow and how to prevent water from entering the well /47/.

The hydrocarbons are driven out of the rock formation and into the well due to formation pressure. The formation pressure is a function of hydrostatic pressure exerted by the column of water extending from the stratum to the surface, rock grain pressure from the overlaying load, gravity pressure due to differences in height, solution gas drive due to dissolved gas in the oil and gas cap pressure derived out of free compressed gas. Normal pore pressure is usually equal to the hydrostatic pressure of the water column. However, there are always exceptions /47,54/. When oil, gas and water are extracted, the pressure will start to sink until the well is depleted. The average reservoir recovery rate is about 40 %, leaving 60 % of the hydrocarbons trapped in the reservoir /8/.

## 2.6 Oil well construction

Completing a well includes several steps, such as casing, perforation, stimulation, tubing, installation of the wellhead and, if necessary, stimulation of the formation in order to get an adequate flow rate.

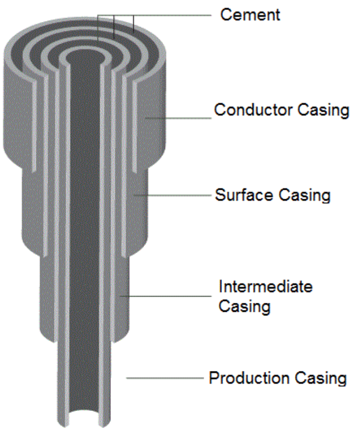


**Figure 10 Casing and cementing /13/**

The casing is the well component which is firstly put in place. It consists of series of metal tubes initially hanged down into the newly drilled hole. The casing is arranged so that the section with the widest diameter is set on top. The diameter then decreases with depth, and the next casing section always fits inside the previous one, as shown in Figure 10 /8/. The purpose of the casing is to protect the hole from mud, prevent carvings, protect fresh ground water deposits from contamination, to provide a smooth entry for tools and to isolate the down hole production zones. Each casing tube is fixed in place one by one by circulating cement slurry down the pipe and up through the annular space between the casing and the hole. It is of major importance that it is an unbroken cement sheet, so that no fluid movement and/or pressure transmission occurs vertically through the annulus, which is the space between the tubing and the casing. When ready, the drilling can continue as planned until an additional casing section has to be set in place /47/.

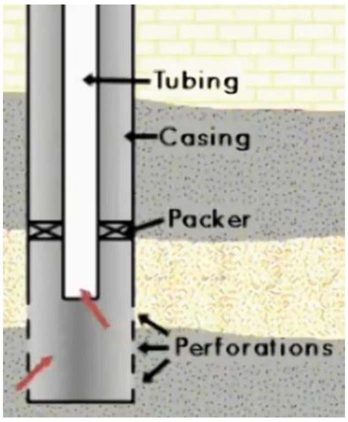


**Figure 11 Shows casing, tubing, packer and the perforating holes /47/.**

Once the casing is installed, a production tube is inserted from the opening at the top to the bottom of the hole, see Figure 11. The diameter of the production tube typically ranges in 5-28 cm /8/. The production tube is mechanically held in place by packers which also seal off the space between the outside of the tubing and inside of the casing. Therefore the casing is protected from corrosive fluids entering the well. The packer has one or more holes where single or multiple strings of tubing can pass through. Finally the Xmas tree is installed. The Xmas tree is designed to withstand full reservoir pressure and prevent blowouts, an uncontrolled release of hydrocarbons. Several control devices are used to control the flow in and out from the production tubing's upper part /47/.

## 2.8 Basic introduction of subsea systems

A subsea system is multi component seabed system used for offshore production of hydrocarbons in deep water up to 3000 meters, where a conventional fixed platform cannot be installed or is considered unprofitable. The subsea system can be positioned many miles away at inaccessible places and is tied back to a host facility through an export pipeline up to 100 kilometres, see Figure 12. The system comprises a subsea completed well, subsea wellhead, subsea production tree (Xmas tree), a subsea tie-in to flow line system and subsea equipment and control facilities. The installation cost for a subsea system is almost independent of water depth, which is a huge advantage against conventional platforms. Deeper water therefore favours the use of subsea systems. However, the need of mobile drilling units also increases the drilling costs, whereupon subsea systems are mostly preferable if there are smaller amount of wells are to be drilled /3,31/.

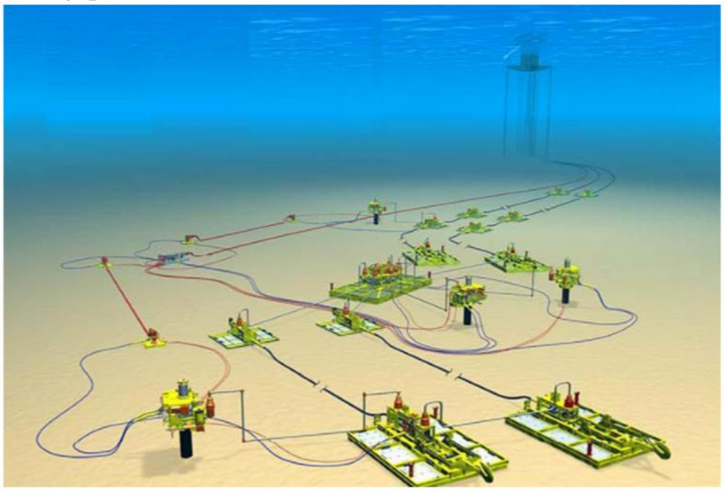

**Figure 12 Illustration of a Subsea system /3/.**

## 2.9 Main components in a subsea production system

A subsea system consists of different kinds of equipment tied back to a host facility. The host facility is usually a topside structure, which is further described in Appendix C. The main parts of the subsea production system are listed and described below /31/:

- Wellhead & Xmas tree
- Pipe line and Flow line
- Subsea manifold
- Umbilical system
- Termination unit
- Production riser
- Template
- Jumpers

### 2.9.1 Wellhead & Xmas tree

A subsea wellhead is located at the top of a well. The purpose of the wellhead is to regulate and monitor the flow of hydrocarbons from the well bore, preventing leakage of gas or oil and prevent blowout due to high pressure. Therefore the wellhead has to withstand an upward pressure, up to 1400 bar, from gases and liquids. The components of the wellhead are the wellhead housing, conductor housing, casing hangers, annulus seals and guide base, Temporary Guide Base (TGB) and Production Guide Base (PGB). The high-pressure wellhead housing is the primary pressure containing body for subsea wells which support and seals the casing hangers and transfer external loads to conductor housing and pipes, see figure 13 /3,8/.

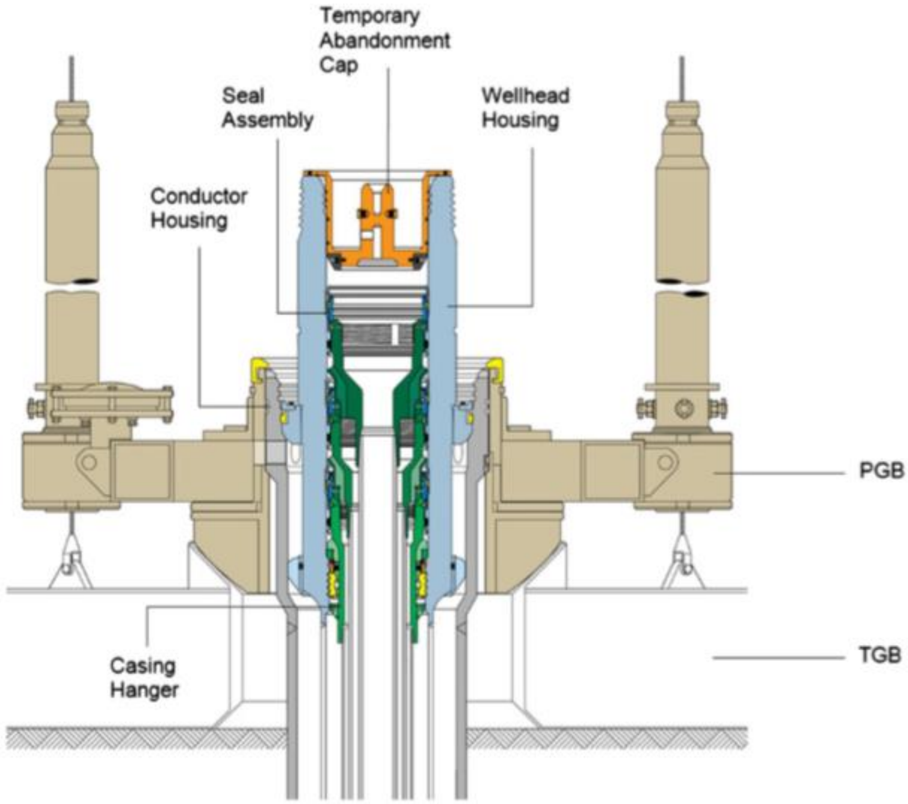


**Figure 13 A typical wellhead system /3/**

The subsea production tree, also called Xmas tree, is placed on the top of the well bore. It is an arrangement of valves, pipes, fittings and connections and can be either vertical or horizontally constructed. Horizontal Xmas trees are especially used in subsea production systems. The concept is beneficial for a well that needs plenty of intervention, but the price is also in range five to seven times higher than a conventional Xmas tree /3,8/. There are three main valves in a Xmas tree, Surface controlled subsurface safety valve/Down hole Safety Valve (SCSSV/DHSV), Production Master Valve (PMV) and Production Wing Valve (PWV). Vertical trees also use a Swab Valve (SW) to get access for intervention and work over operations, while horizontal trees rely on electrical submersible pumps. The first three valves mentioned, DHSV, PMV and PWV, are considered as Independent Protection Layers (IPLs) and may be used in order to stop the flow of hydrocarbons. A schematic illustration of a horizontal Xmas tree is shown in figure 14.

The Xmas tree also has a Production Choke Valve (PCV) which enables control of the flow close to the wellhead. The choke is made of high quality steel in order to withstand extreme stain. However, it is not defined as an independent protection layer as it is usually defined as a part of the Basic Process Control System (BPCS). All Xmas tree valves can be operated by electrical or hydraulic signals from topside though the umbilical systems, manually by divers or manually via a Remote Operated Vehicle (ROV) /8,31/. There are no critical functions which are only controlled from topside, except the DHSV witch cannot be accessed by ROVs[1].

A Xmas tree can be placed either as a wet tree or as a dry tree. If it is placed as a wet tree, it is exposed to the seabed condition. Otherwise, as a dry tree it is placed at the hull of the host facility. During this thesis only wet tree systems are considered as subsea systems. Globally, more than 70% of the wells in deep water fields are using wet tree system, which demonstrate the industry's confidence in these systems. However, dry trees are widely used in shallow and medium water complexes /3/.

[1] Morten Nilstad Pettersen, Senior Safety Consultant at Oilconx Risk Solutions (ORS)

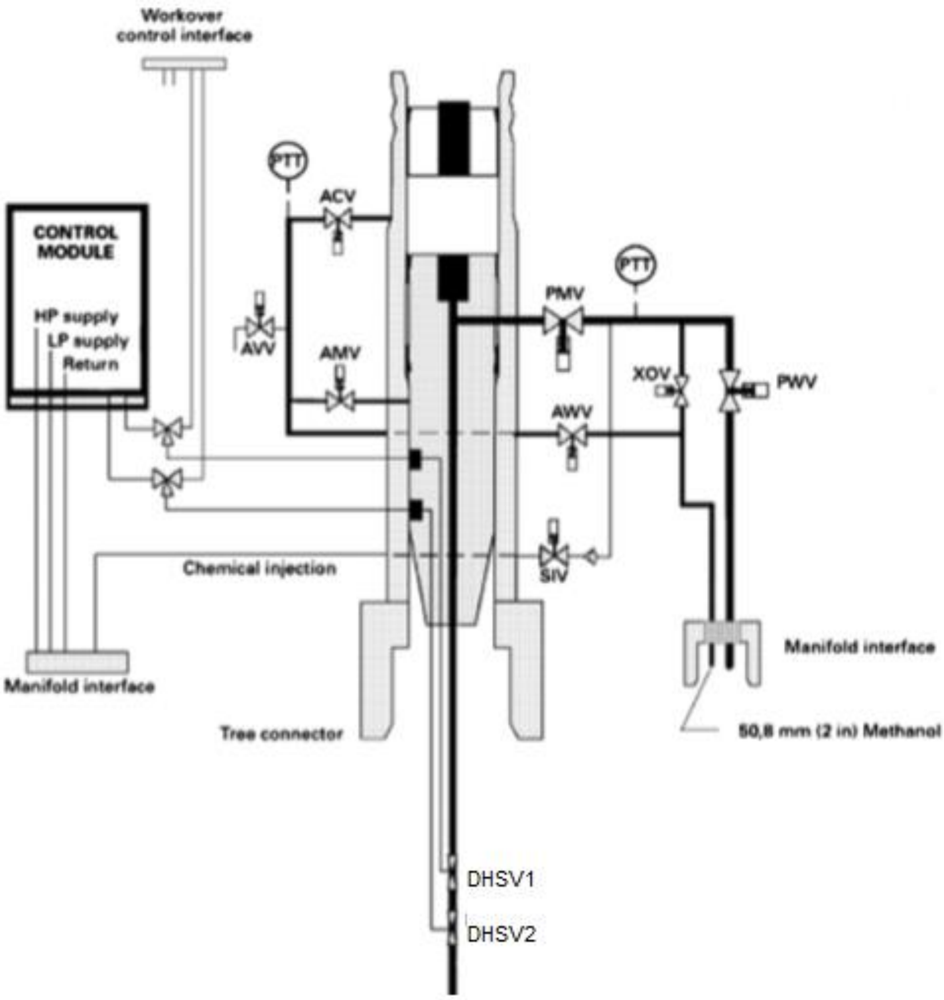


**Figure 14 Show schematic off a horizontal Xmas tree /3/**

### 2.9.2 Pipelines and flowlines

Subsea pipelines are installed for transportation of fluids between two different facilities while flow lines are transportation units within the production system. Pipe- and flowlines can be used for hydrocarbon transport, lift gas, injection water and other chemicals and can be constructed as a single pipe, as a pipe-in-pipe with double walls or as a carrier pipe with multiple lines inside. The size of the pipe depends on its purpose.  In subsea production, one single pipe can vary in the range of 1 meter to 100 kilometres and longer pipes are typically about 450 mm in diameter. The pipes may need to be insulated in order to avoid problems with cooling fluids when transported along the sea bed. Too cold temperatures may lead to formation of hydrate or wax plugs /3,31/.

### 2.9.3 Subsea manifold

Subsea manifolds are gravity based structures serving as central gathering points for several subsea wells. The function is to simplify the subsea system, minimize the use of pipelines and risers and optimize the flow of fluids in the system. The manifold simply forwards the common flow to the host facility. Piping and valves are designed to combine and monitor flows from several wells or to inject water into the wells. The subsea manifold may be installed either as a stand-alone structure or as an integrated part of the well template. To increase lateral stability it can either be anchored with piles or be equipped with a skirt to penetrate the mud line /3,31/.

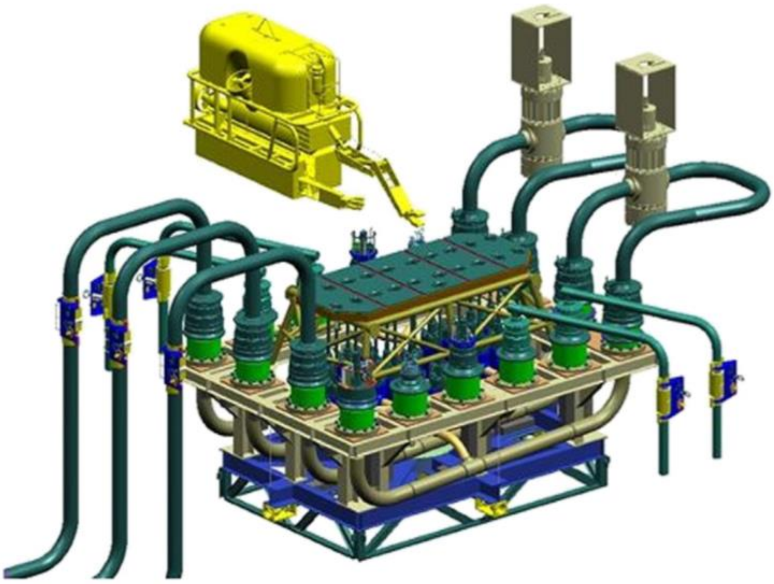

**Figure 15 Manifold maintained by a ROV /3/**

The size of the manifold is dictated by the number of wells in the system and how well they are integrated. The shape is usually rectangular or circular and a likely range of a circular system may be a diameter of 24 meters and height up to 9 meters above sea floor /31/. Figure 16 shows an example of a subsea manifold system.

### 2.9.4 Umbilical systems

An umbilical system is an arrangement of tubing, piping and electrical conductors extending through an armoured casing, stretching from the host facility to the subsea equipment. The function is to transmit the control fluid and/or electrical signals needed to control the functions of the production system and the safety equipment, such as Xmas tree, valves and manifold unit. The umbilical system can also be used to monitor pressure or inject chemicals, such as methanol, into critical areas of the system. The umbilical dimensions typically range up to 10 inches in diameter. The number of tubes and its length depends on the production system complexity and the distance between the host facility and the tied-in equipment /3,31/.

### 2.9.5 Termination unit

A termination unit is a subsea structure placed at the end of a flowline, pipeline or umbilical in order to attach them to a subsea unit. Termination units are positioned on, or as an integrated part, of a subsea unit, such as a manifold or a template /3/.

### 2.9.6 Production riser

A production riser is a flowline which stretches between the seabed and the host facility. The riser dimensions normally range between 3 to 12 inches (76,2 – 304,8 mm), in diameter and the length varies according to water depth and riser configuration. A riser can be contained within the area of the host facility, run in the water column or drawn along the sea bed. It can be constructed either as a flexible or rigid installation. Some production risers are equipped with a subsea isolation valve (SSIV) capable of stopping the hydrocarbon flow /3,31/.

### 2.9.7 Template

A template is a fabricated structure which houses other subsea equipment. It can take any shapes but is typically rectangular. The size may differ considerably, but are usually in range 3-50 m long, 3-20 m wide and 2-10 m high /31/. The templates protects the subsea equipment from external damage, e.g. from trawlers, and also facilitates the wells to be drilled and serviced from the surface /8/. The template can accommodate different equipment such as trees in tight clusters, manifolds, pigging devices, termination units and chemical treatment equipment /3,8/. An example of a subsea template is shown in figure 18.

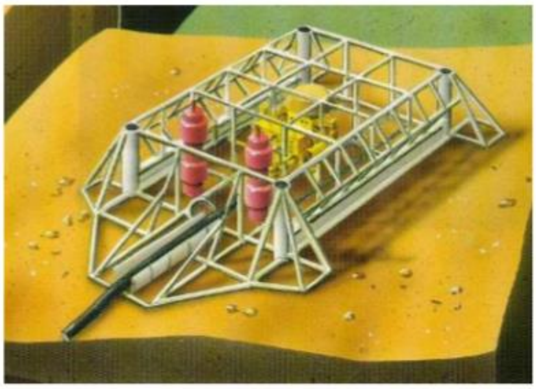

**Figure 16 Illustration of a subsea template /8/**

### 2.9.8 Jumpers

A jumper is a short pipe connector used for transportation of fluid between subsea components, for example a Xmas tree and a manifold unit, or to inject water into a well. Flexible jumpers provide adaptability unlike rigid jumper system /31/. Figure 19 shows an example of a jumper.

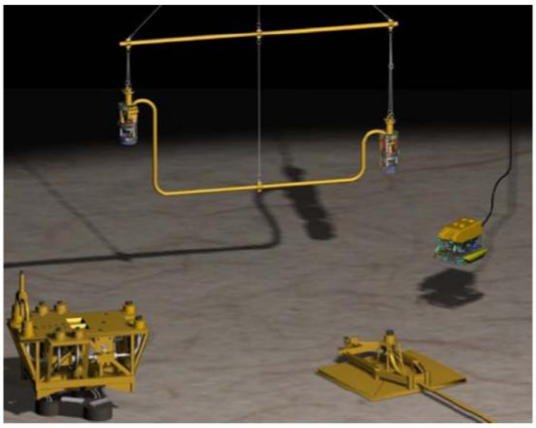

**Figure 17 shows a jumper /3/**

## 2.10 Subsea field design

When defining field architecture several factors should be considered. The main aspects are listed below:

- Dry tree or subsea system
- Stand alone or tie-back development
- Subsea layout
- Subsea processing
- Artificial lift methods
- Facility configuration

First of all, the water depth determines if the field should be developed as a subsea production system or as a conventional dry tree system. The water depth can be categorized in shallow water less than 200 metres, deep water between 200 and 1500 metres and Ultra-deep water in which water depth is greater than 1500 metres. Deep water and Ultra-deep water seems to favour the use of subsea production systems /3/.

### 2.10.1 Tie-back system or stand-alone facility

If choosing a subsea production system it can be constructed as a tie-back system or a stand-alone system. A tie-back system refers to utilizing the capacity of already existing infrastructure instead of building new structures for every field, which significantly lower the initial costs. However, the economic advantage depends on several factors such as distance from existing installation, water depth, recoverable volumes of oil and gas, reservoir size, complexity and the potentially and lower recovery rate compared to stand alone facilities.

The design specification of the subsea flowlines are driven by the need of proper flow. It is of major importance that the fluid can arrive to the end destination above critical temperature, such as wax appearance-, cloud point- or hydrate creation temperature. Hydrates, wax, asphaltene, scale or sand cannot be allowed to build up and block the flowlines. It is also crucial that the flowlines can be able to work properly after a planned or unplanned shutdown, particularly with respect to hydrate blockage /3/. It is a technical challenge to ensure that it does not happen.

The pressure must ensure sufficient hydrocarbon flow rate and heat have to be conserved, e.g. by flowline insulation. Chemical treatment may also be necessary. If there is a longer production stop, fluids can be pushed back down the well so that the cold oil does not plug the flowlines. If there are long tie-back developments, subsea processing or artificial lift methods can be used to ensure that the hydrocarbons reaches its intended destination /3/.

A stand-alone development hand means construction of a new subsea field including a new host facility. The initial cost is higher, but it may be a good investment over time when the complete life cycle is taken into account. A stand-alone unit can provide higher recovery rates due to easier well intervention and work over operation. Furthermore, the new facility can be constructed in a way so that no limitations in the host processing functions appear throughout the lifetime of the field /3/.

### 2.10.2 The subsea system layouts

The well location plan is usually an exercise in balancing different interests. A preferable spacing of the wells for good recovery stands against the cost savings of grouping wells together. Reliability and risk assessment are also dominant factors when the layout shall be decided. Reliability assessment comprises production availability and maintenance costs, while risk assessment is performed in order to reduce the potential for consequences realization of an unwanted event /3/.

A subsea field can be organised in multiple ways. A single satellite well can produce directly to the surface by a flow line connected to the host facility or it can be linked to a manifold which forwards the hydrocarbon flow to the host facility. The advantage of a single well is the flexibility of location, installation, control and service. Each well is handled separately so that production can be optimized. Satellite wells are typically used for small fields which require few wells /3,31/.

The other alternative is to let the wells be grouped closely together in formations, such as multi-well satellite formation, cluster formation, template formation or daisy chain placement, see Figure 18. The advantage of arranging the wells in such a way is the ability to share common functions, such as manifold service, shared injection lines, control equipment, flow lines and umbilicals. Furthermore, a production manifold may collect the production from all wells and redistribute it to the host facility in a single flowline and thus reducing the overall installation costs. However, these systems increase the need of subsea chokes for individual well control. Another disadvantage is that work over operation may interrupt production from many wells simultaneously. The wells may be placed with tenth meters of spacing /3/.

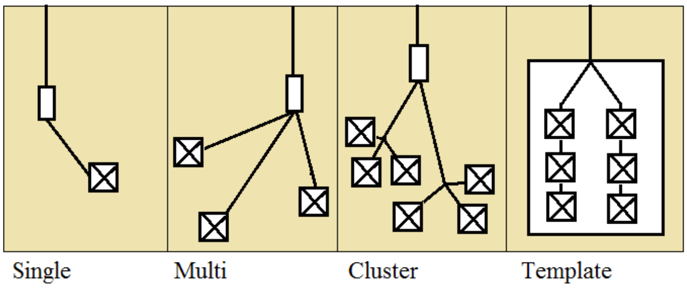


**Figure 18 Common subsea layouts**

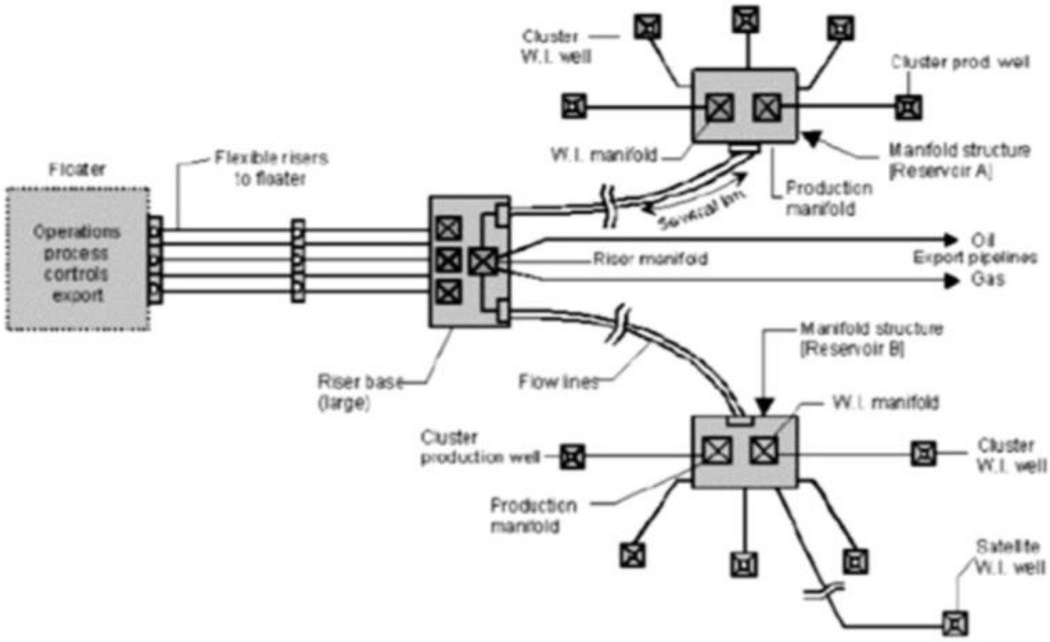


**Figure 19 Show how cluster arrangement can look like /3/**

A well template is designed to group wells closely together and may support more than a dozen wells. The advantage is that pipes and valves can be integrated into the structure, the wells are being precisely spaced and pipelines, umbilicals and jumpers may be pre-fabricated. The template provides short flowline and piping distances and the equipment are protected by the template structure. The disadvantages however are the longer design and fabrication time, less flexibility in well location, less ROV access and increased vulnerability to subsurface instability /3/.

The daisy chain placement on the other hand consists of two or more wells linked by dual flowlines in series. Each well has a choke to avoid pressure imbalance. The use of dual flowlines allows round trip pigging. It also provides the ability of diverting both production lines into one if the second are damaged and provide the ROVs with good access. Since there are no mechanical connections between wells, they can be spread out over great distances. However, when the number of wells increases other solutions should be considered /3/.

# 3. Hazard and initiating cause identification

This chapter comprises a hazard- and initiating cause identification and is divided into two main sections. The first section describes the hazards, i.e. what can go wrong and what the consequences are. In the next section, several initiating causes are identified and described. An initiating cause is a failure mechanism acting as prerequisite for a hazard to occur.

The identification process is based on a number of assumptions, such as best practice system design, appropriate maintenance of the system and that all activities affecting the safety life cycle is handled by competent personnel. Hence, if the data provided in this chapter shall be used in the following LOPA SIL-determination process, it must be ensured that following criteria are fulfilled:

- The design pressure of the Xmas tree is above full reservoir pressure;
- The design pressure of chemical injection service line and annulus is above full reservoir pressure;
- The subsea system has an inherently safe design due to expected temperatures of oil, water and injected chemicals. The design shall prevent damage due to overpressure or material degradation;
- No corrosion and material degradation due to chemical incompatibility;
- Pipelines, flowlines and riser are built according to international standards;
- Maintenance work is properly performed according to international standards.

If these requirements are not met the subsea system has to be evaluated specifically. Expert engineering judgement should be used to do necessary corrections due to possible hazards, failure mechanisms and coupled failure frequencies.

## 3.1 Hazard identification

The surroundings of an offshore platform is divided into different sections, see Figure 20. The safety zone extends with a 500 meter radius from a central point of the topside facility. The purpose of the safety zone is to protect the offshore workers and the facility against external damage. No vessels are allowed to enter the zone without special permission /25/. In this thesis, an assumption is made that a hydrocarbon release within the safety zone causes environmental, commercial and safety impact, while a release in the open se zone is not considered a safety threat. However, a release in open sea zone still generates the same environmental and commercial impact as in safety zone.

The following hazards have been identified by brainstorming in technical groups, studying previous HAZOPs and by reading technical literature. The studied HAZOPs are found in Appendix D. The initiating causes, presented in section 3.2, were taken into account during the hazard identification process.

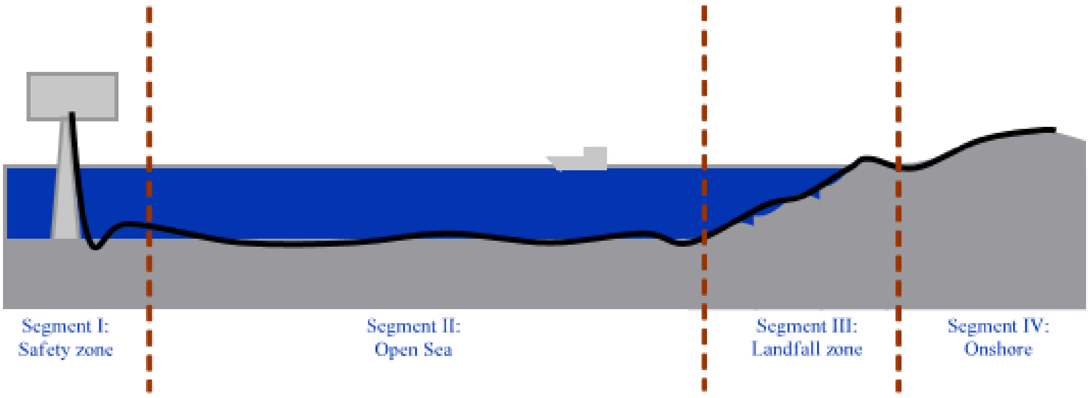


**Figure 20 Section classification /44/**

### 3.1.1 Damage of pipelines and flowlines.

Pipe- and flowline leakages are major threats, which can lead to huge environmental and commercial consequences. In addition, leakages within the safety zone can lead to fatalities due to fire and/or gas cloud explosions on, or near, the topside facility. Initial causes can be critical load such as trawler activity, ship anchors/sinking ships, subsea landslide, dropped objects or hammer effect. Major failure mechanisms acting over time can be corrosion, erosion and marine growth. If the pipe- and flowline are not designed to withstand full wellbore pressure, stopped flow due to plugs or topside Emergency Shutdowns (ESDs) may lead to critical overpressure. Structural weak spots are typically areas where pipeline segments are welded together.

### 3.1.2 Destruction of Wellhead and/or Xmas tree

A damaged wellhead or Xmas tree is a serious incident which can initiate huge hydrocarbons releases. A Xmas tree can typically be damaged by dropped objects, trawling activities, anchors, sinking ships and subsea landslides. The reasons for wellhead leakages to occur may be corrosion or internal overpressure. Since wellheads and Xmas trees are usually placed outside the safety zone, leakages are assumed to cause environmental and commercial impact but no safety impact. Four identified events leading to damage of wellhead or Xmas trees are further described below:

- Leakage from Xmas tree endpoints: The endpoints of the Xmas tree are considered as structural weak spots where leakage would possibly occur. A leakage would cause contamination of environment and commercial losses and/or result in water entering the system. Sea water contains salt which increases corrosion.

- Internal overpressure: If the DHSV is closed meantime chemicals are injected into the well, it may result in an increased pressure with potential of exceeding the Xmas Tree design pressure. Chemical injection is performed by topside pumping equipment, usually equipped with safety valves.

- Leakage from annulus: If the well is sealed and pressure are built up in the wellbore, hydrocarbons may enter the annulus and create wellhead leakages. While the well is often placed a long distance from the host topside facility, there will be environmental and commercial consequences but no safety impact.

- Valves are mechanical instruments and thus weak spots on the structure. Leakage may occur due to heavy loads or mechanism acting over time, such as corrosion and erosion.

### 3.1.3 Manifold collapse

A manifold unit usually handles a large amount of oil since it merges several flowlines and forwards the common hydrocarbon flow to the host facility. A collapse can therefore lead to devastating consequences. Failure mechanisms can be critical loads such as loads from trawls, ship anchors, subsea landslides, dropped objects or mechanisms acting over time, such as erosion and corrosion. If the manifold is not build to withstand full wellbore pressure, stopped flows due critical plugs or topside ESDs, without sealing of the manifold unit may cause critical failures. The leakage consequences are usually environmental and commercial, since the manifold is normally placed outside the safety zone. A manifold unit is often protected by a subsea template. The weak spots of a manifold unit are listed and described below:

- Future connections to the manifold: Future manifold connections are structural weak spots which may cause large scale releases of hydrocarbons, comparable with full pipeline ruptures. Initial causes are almost the same as for pipelines, with exception of a possible template protection installation.

- Insufficient sealing of connectors: A manifold consists of several sealing and connectors, which when broken can lead to hydrocarbon release.

- Valves and steel defects: Valves are mechanical instruments and thus weak spots on the structure. Since the manifold consists of several parts, steel defects during construction may, with time, cause hydrocarbon leakages.

### 3.1.4 Rupture of riser

A rupture of riser is a serious accident which can be the result of extreme weather conditions, collision with ships or icebergs, fire and/or explosions on topside deck, sabotage and/or dropped objects. Also mechanism acting over time, such as corrosion, erosion, marine growth and plugs are major failure mechanisms. A riser rupture is an environmental and commercial threat, but also a safety threat since the incident occurs inside the safety zone.

### 3.1.5 Topside blowout

A blowout is an event where formation fluid flows out of the well after all protection layers have failed. The scenario is more frequently occurring at drilling wells but may occur during production phase as well. In this thesis, a topside blowout is defined as a release occurring on the topside facility. It is only considered as a safety impact event, since environmental and commercial impact is already included in other subsea leakage categories.

## 3.2 Initiating causes

Roughly, the prerequisite failure mechanism of a hazardous event can be divided into two main groups, where one is related to critical loads and the other to gradually weakening over time, as shown in table 3. In this section, each initiating cause will be further described.

**Table 3 Different failure mechanisms**

| Critical loads | Mechanism acting over time |
|---|---|
| Loads from trawls | Corrosion |
| Ship anchor/sinking ships | Free spans |
| Subsea landslide | Buckling |
| Dropped objects | Erosion |
| Fire & Explosions | Plugs |
| Sabotage | Marine growth |
| Collisions | Vibrations |
| Hammer effect | Material defects |
| Extreme weather conditions | Joule-Thomson effect |

- Loads from trawls

Pipelines and flowlines are normally dimensioned to withstand trawler impact. However, impact can cause buckling or fractures on smaller pipes. A trawl can also get stuck in exposed flanges and bolts and thereby cause damage to the subsea structure. Pipelines are not designed to tackle fishing with lumps, which is a relatively new practise. The consequences of such an impact are still unknown. Templates are able to protect some subsea equipment, such as manifolds and Xmas trees /44/.

- Ship anchor/sinking ships

Anchors or sinking ships hitting subsea equipment on its way to the bottom or anchors snagging on flowlines/pipelines can cause quick fractures. The impact frequency depends on traffic density, distance from shore or port, water depth and vessel traffic surveillance /44/.

- Subsea landslide

Subsea landslides may cause pipeline fractures or damage other key equipment. An unstable seabed can eventually lead to template collapse, which generates a risk for nearby vital subsea units.

- Dropped objects

Dropped objects and/or cargo may hit a pipeline, riser or other vital subsea equipment, even if not dropped directly above the subsea installations. It can happen during well intervention operations or during lifts from ships and/or topside facility. Pipeline protection is not always in place, and templates are not always capable to provide adequate protection against heavy dropped objects.

- Fire/Explosions

Fire and explosion are prominent incidents in the offshore industry. Fire and explosions usually occurs at the topside facility, but can also be a result of a subsea leakage. Surface fires or gas cloud explosions may cause multiple fatalities, environmental impact and/or an uncontrolled hydrocarbon releases.

- Sabotage

Oil facilities can be military targets in both tribal wars and conventional wars. In the Niger delta, sabotage contributes to more than 50 % of the onshore pipeline ruptures /1/. Air strikes against offshore facilities have also contributed to some of the worst oil spill disasters in history /34/. Sabotage and/or hostile military actions shall be seen as a political risk factor which differs between nations and regions.

- Collisions

A collision between a vessel and a subsea topside facility can damage the subsea part of the riser and cause a major oil release. Even though GPS systems have significantly decreased the number of collisions, it still happens at a regular basis. Collisions with icebergs can also be a major threat, since some icebergs can be hard to eliminate or force into another direction.

- Hammer effect

Hammer effect is a pressure surge caused when a flowing fluid is rapidly forced to stop and changing direction. The kinetic energy of the flow is rapidly converted into pressure energy causing a high pressure wave spreading through the system. Hammer effect may cause problems in range of vibrations to full pipeline collapse.

- Extreme weather

Extreme weather such as storms and huge waves are heavy loads on topside facilities. It can cause floating facilities to drift away, cause damage to the riser installation or induce vibrations spreading through the subsea system.

- Corrosion

Corrosion is a chemical reaction which can damage and/or weaken materials. Several compounds in the hydrocarbon flow are able to cause corrosion in almost any parts of the subsea system. Corrosion is a huge failure mechanism in offshore pipeline systems and tends to increase with time /36,44/. Internal corrosion is the major factor of pipeline wall thinning during operation phase, depending on hydrocarbon composition, presence of water and operational changes. The damage may be inflicted due to $CO_2$ corrosion, $H_2S$ stress corrosion cracking or microbiological-induced corrosion. External corrosion is normally not a big issue regarding subsea pipelines, since they are often protected by corrosion coating. However, since corrosion increases with time damage can, when initiated, develop at a high rate /3/.

- Free spans

Free span develops when the soil beneath the subsea system is washed away. A free span also influences already existing spans in near distance, making them evolve even faster. When a free span is fully developed it can cause fractures on pipelines relatively quickly due to fatigues. One such incident is known from China when free spans developed during extreme weather conditions. Free span occurs in almost every pipeline drawing if no special conditions, such as burial, are present. Especially in soft soils, free spans tend to shift position and vary in length. Free spans can also lead to template instability, finally causing a collapse damaging everything beneath it. The possibility of a template collapse shall especially be taken into account in areas where earthquakes frequently occur /3,44/.

- Buckling

Buckling sideways or upwards can occur if the pipeline is prevented from extension. This can cause great strains on local parts of the pipeline. The event most commonly occurs during the early life of a well, when hydrocarbon temperature is at its highest level /44/.

- Erosion

Erosion is an abrasion process which appears when slurry and sand is transported in pipelines. The phenomenon mostly occurs at bends, reduced diameter or at pipeline connectors. The defects are similar to those caused by corrosion and failure frequency usually increases with time. The erosion rate is proportional to the mass of sand in the fluid where large particles cause more severe damage. However, the erosion is also proportional to the power of 2.5-3.0 the velocity, and therefore it is usually not a huge problem if the velocity is less than 3-4 m/s /3,36/.

- Plugs

For a given hydrocarbon fluid, solids able to plug pipelines occur at certain pressure and temperature. These hydrates- and wax deposits may stop the entire production /3/. If there is no inherently pressure safe design, a plug may cause pressure build up and pipeline rupture. Hydrate plugs can be handled by control and maintenance operations, such as temperature and pressure control, chemical injection and pigging.

- Marine growth

Marine growth on pipelines can create thick isolating shale on the outside of pipelines and flowlines. The isolating shale can cause hydrocarbon temperature to increase, potentially exceeding the design limit. This incident is more likely to occur downstream, near the wellhead, due to warmer fluids. Protection from marine growth is necessary in most areas but especially in warm water.

- Joule-Thomson effect

The Joule-Thomson effect occurs when a fluid suddenly expands from a high pressure state into a low pressure state. It is an adiabatic effect since it happens too quickly for any heat transfer to occur. The pressure drop is accompanied with a sudden drop in temperature, which may lead to material degradation if the temperature exceeds the system design limit. In subsea context, Joule-Thomson effect occurs during a production start-up procedure when to re-establish the normal hydrocarbon flow.

- Material defects

The weak spots on a subsea system are usually non solid areas, such as welding or connectors. If there are any construction or steel defects present, these may be developed into leakages with time or directly due to heavy loads.

- Vibrations

Vortex induced vibrations are an important source of fatigue damage on offshore structures. Vortexes can be initiating by the current flow, topside facility motions or from natural hazards, such as earthquakes or extreme weather conditions. Regardless of the original source, vibration leads to reduced fatigue strength and leakage.

# 4. Base failure frequency

The base failure frequencies for subsea equipment are based on generic data from known sources, such as OREDA (2009) and OGP (2010). Generic data is averaged in nature, but provides a good base estimate able to modify in order to better reflect reality. Only the failure mode "leakage" is taken into account, since other failure modes are assumed not to give environmental, commercial and/or safety impact. In order to use the statistical data presented in this chapter, the criteria bullet-listed in section 3 should be fulfilled.

This chapter is divided into two sections. In the first section, strictly generic frequencies for subsea units are tabled. Only subsea units contributing to the overall system hydrocarbon leakage frequency are taken into account. Consistently, subsea units which are not contributing to direct hydrocarbon leakage, such as templates and umbilical systems, are omitted. Other subsea units, such as termination units, flowlines and jumpers are already included in the tabulated values. Termination units are, according to the original source, considered as a part of the tabulated subsea units. Jumpers and flowlines on the other hand are assumed to have the same leakage frequency as pipelines.

In the next section, methods for adapting these failure frequencies into specific subsea system properties are provided. The calculated result is assumed to reflect the overall generic system leakage frequency.

## 4.1 Generic base frequency

Table 4 presents generic values coupled to wellhead & Xmas tree and manifold units. The generic data is collected on a complete unit lifetime basis, i.e. start when it is installed, tested and ready for production. The statistic is limited to failure of hardware equipment. Failures due to human errors are, implicitly, included in the failure rate estimate. The failure rate is presented as a mean value based on the mean failure rate among the installations for which data has been collected /46/. In the original source, leakages were divided into three severity categories, critical, degraded and incipient failures, where critical is defined as the most severe failure type. In this thesis, only critical leakages have been considered since smaller leakages are not assumed to cause environmental, commercial or safety consequences.

The maintenance time (T) is the average calendar time during which repair work is actually performed. Preparation time is not included in the time estimate. T shall therefore not be mistaken for being the same as the oil spill duration time. Furthermore, the maintenance time for Wellhead & Xmas trees and manifolds are based on the mean repair time needed to repair critical external leakages. The same maintenance time was set on broken manifold connectors, while no other data was available for that sort of failures. When estimating the oil spill duration time, the maintenance time shall be multiplied with the leakage mass flow and a correction factor, determined within the LOPA expert group. Note that the duration time estimate is a worst case scenario, e.g. when all mitigating SIFs fail to stop the hydrocarbon flow.

The topside blowout base frequency is assumed to be the same as the generic blowout frequency for offshore production facilities. That is a conservative estimate, since the generic blowout frequency from the original source also covers blowouts far away from the topside facility. However, the base topside blowout frequency can be modified within the LOPA group when determining the risk by changing specific adjustment parameters, see chapter 7.

**Table 4 Failure rates, consequence estimation and maintenance time for manifold and Xmas trees and wellheads /46/**

| Equipment class | Failure | Failure rate / Year [$10^{-5}$] | T [Hours] |
|---|---|---|---|
| Wellhead & XMAS Tree [All types] | External leakage | 342 | 124 |
| Wellhead & XMAS Tree [Conventional] | External leakage | 377 | 124 |
| Manifold [All types] | External leakage | 596 | 126 |
| Manifold [All types] | Free open connectors | 79 | 126 |
| Topside blowout | Unstoppable hydrocarbon flow | 0.98[1] | - |

[1] Generic blow out frequency for production facilities according to SINTEF (2011)

Base failure frequencies for pipelines and risers are found in Table 5. The failure frequency for risers includes risers to FPSs, TLPs and semisubmersibles (see Appendix C), but not deep water technologies such as steel catenary risers due to lack of data /44/. Furthermore, a conservative estimate is made that flowlines and jumpers have the same failure frequency as pipelines.

The maintenance time to repair a leak, T, is chosen as the most conservative value. Pipeline maintenance time is based on reparation of degraded external leakages while riser maintenance time is based on reparation of critical external leakages. The repair time is a critical element when to estimate the total hydrocarbon spill amount, in order to determine the severity of a consequence.

**Table 5 Failure frequencies for pipelines and risers /44/**

| Equipment class | Failure | Diameter [Inch] | Failure frequency [$10^{-5}$] | Unit | T [Hours] |
|---|---|---|---|---|---|
| Pipeline in open sea | Leakage | All | 50 | Per km · year | 24 |
| Flexible pipelines in subsea | Leakage | All | 230 | Per km · year | 24 |
| Subsea pipeline in safety zones | External loads causing damage in safety zone | ≤ 16 | 79 | Per km · year | 24 |
| Subsea pipeline in safety zones | External loads causing damage in safety zone | > 16 | 19 | Per km · year | 24 |
| Riser of steel | Leakage | ≤ 16 | 91 | Per year | 168 |
| Riser of steel | Leakage | ≥ 16 | 12 | Per year | 168 |
| Flexible riser | Leakage | All | 600 | Per year | 168 |

## 4.2 System specific base frequency

Properties of many subsea systems can vary due to various subsea units and subsea system layouts. The base failure frequency therefore has to be adapted into a specific subsea system base frequency. The subsea system properties, such as size, pipeline length, number of manifolds etcetera, have to be taken into account. In order to adapt these base failure frequencies, equation 2 to equation 5 can be used. These equations have been especially created for this purpose and are further explanation in the text below.

### 4.2.1 Manifold

The generic failure frequency for the manifold in Table 4 is given for a “standard manifold” with four connections to well flowlines. Therefore, failure frequency of possible open connectors has to be added. If the number of wells differs, for example eight wells instead of four wells, then the total failure frequency shall be doubled. Xmas trees and control systems are considered outside the boundaries of the manifold. The calculation process is shown by equation 2.

(Equation 2) $F_{B.manifold}=\left[(1/4 \cdot X)\cdot F_{(generic\ manifold)}+(Y\cdot F_{connector})\right]$

| | |
|---|---|
| $F_{B.manifold}$ | =Total base release frequency for a specific manifold structure |
| $F_{(generic\ manifold)}$ | =Base Failure frequency for manifolds according to Table 4 |
| $F_{connector}$ | = Failure frequency for free connectors according to Table 4 |
| X | = Number of wells |
| Y | = Number of free connectors |

### 4.2.2 Pipeline system and safety zone pipelines

The generic failure frequency for pipelines are given as per km · year unit, see Table 5. In order to get the total pipeline failure rate, the frequency has to be multiplied by the total pipe length. The frequency for external loads within the safety zone has to be added. The calculation process is shown in equation 3.

Since the safety zone conditions differ from open water conditions, the safety zone base leakage frequency has to be especially evaluated. It is made by using equation 4.

(Equation 3) $F_{B.Pipelines}=[l\cdot f_{km}+(X\cdot 0{,}5\cdot EL)]$

(Equation 4) $F_{B.P.SafetyZone}=X\cdot 0.5\cdot (f_{km}+EL)$

| | |
|---|---|
| $F_{B.Pipelines}$ | = Total base release frequency for a specific pipeline system [per year] |
| $F_{B.P.SafetyZone}$ | = Base pipeline release frequency within safety zone [per year] |
| $f_{km}$ | = Release frequency for pipelines [Per km · year], Table 5 |
| l | = Length of pipelines [km] |
| X | = Number of pipelines stretching through the safety zone |
| EL | = External loads within safety zone |
| 0.5 | = Refers to the safety zone of 500 metres |

### 4.2.3 Riser

The generic failure frequency for different riser installations in Table 5 is single values, and there is no need for modifying the base frequency due to size or length. There is no significant statistic saying that use of longer riser installation automatically leads to a higher failure rate than use of short riser installations /57/.

### 4.2.4 Wellhead & Xmas tree

The generic wellhead & Xmas trees are given as single values and no modification of the base frequency has to be made. Only the number of wellheads & Xmas trees will affects the subsea system failure frequency. The wellhead & Xmas tree base failure frequency is found in Table 5.

### 4.2.5 Overall system

When calculating the overall system failure frequency, the failure frequencies for all different subsea units simply have to be summarized according to equation 5.

(Equation 5) $F_{B.\text{subsea system}} = F_{B.\text{manifold}} + F_{B.\text{pipelines}} + F_{B.\text{riser}} + F_{B.\text{Wellhead \& Xmas tree}}$

$F_{B.\text{subsea system}}$ = Total base release frequency for a specific subsea system
$F_{B.\text{manifold}}$ = Total base release frequency for a specific manifold
$F_{B.\text{pipelines}}$ = Total base release frequency for a specific pipeline system
$F_{B.\text{riser}}$ = Total base release frequency for a specific riser installation
$F_{B.\text{Wellhead \& Xmas tree}}$ = Total base release frequency for a specific wellhead & Xmas tree

# 5. Risk Acceptance Criteria

Offshore risk analyses have been traditionally focused on safety issues. Presently, it is still the main focus, even though awareness of environmental and commercial risk has increased the last years. Several incidents have been contributing to the increased awareness, not least the Deep Water Horizon accident in year 2010 which lead to multiple fatalities and huge environmental impact /49/. The risk acceptance criteria are defined as the maximum frequency allowed for a specified severity of a consequence. This does however not mean that risk that reaches the acceptance criteria is automatically accepted. The risk should be further reduced using the ALARP principle. The risk acceptance criteria are presented in Table 6, Table 7 and Table 9. All acceptance criteria are divided into 5 consequence classes, where 5 is considered as the most severe.

In all three cases, a linear relationship between consequence and frequency is assumed. In reality that may not be entirely true, since peoples risk perception is affected by multiple factors. However, a linear correlation has the advantage of being user friendly and easy to understand. Since the overall LOPA-model is rather complex, it is beneficial to keep the risk acceptance criteria as simple as possible. The same approach is used in several European countries during regional planning. For example, in the UK the gradient of the FN-curve is set to minus one /18/. The same gradient is used in this thesis.

## 5.1 TMEL

UK Health and Safety Executive (HSE) has implied that the upper tolerability limit for industrial workers individual risk of dying is 1 in 1000 per year, $10^{-3}$/year, based on what is assumed socially acceptable in the UK society. For members of the public, the tolerable risk is set as $10^{-4}$/year /24/. In this thesis the later value, $10^{-4}$/year, is used for one fatality, since it also seems to be common industry praxis /48/. The value is also conservative compared with the HSE recommendation. Similar criteria are used by several big oil companies active in North Sea and/or worldwide. Furthermore, a permanent injury is assumed to be ten times less severe that a fatality and a recoverable injury is assumed to be 100 times less severe than a fatality.

A linear relation is established between all values, For example, the acceptable frequency of 10 fatalities is ten times less than the acceptable frequency for one fatality etcetera. In reality, the risk perception may not be as linear as in table 6. Multiple aspects affects peoples risk perception, such as who is exposed, if the risk is controllable or not, if the risk is perceived as natural or not etcetera /12,40/. However, the linear relation is preferred due to its user friendliness. It can also be argued that it is more logic to use a linear relation than trying to measure risk perception due to psychological factor. Finally, it is important to understand that these TMELs refer to statistical lives used for estimating the benefits out of different safety measures. It is just a tool. A real fatality can never be acceptable even though it can be tolerated.

**Table 6 TMEL for safety consequences**

| | Consequence class | Health and safety consequence | TMEL / Year |
|---|---|---|---|
| 1 | Minor | 1 injury | $10^{-2}$ |
| 2 | Moderate | 1 permanent injury | $10^{-3}$ |
| 3 | Significant | 1 fatality | $10^{-4}$ |
| 4 | Serious | 1-10 fatalities | $10^{-5}$ |
| 5 | Major/catastrophic | >10 fatalities | $10^{-6}$ |

## 5.2 ERAC

Environmental risk acceptance criteria (ERAC) are created in order to establish a link between environmental risk and reliability requirements for subsea safety barriers. The maximum allowed frequency for a topside hazardous event, such as rupture of a pressure vessel, is $10^{-5}$ events per year /49/. It is reasonable to believe that a major environmental consequence shall have a similar risk acceptance criterion. In this case, a major/catastrophic harm event is defined as a hydrocarbon release of 10 000 tonnes. The acceptable event frequency for such a scenario is therefore set as $10^{-5}$ /year, since it corresponds to a major safety impact. All consequence classes are linearly correlated to that event, both in case of release size and allowed frequency, see Table 7.

**Table 7 ERAC for environmental and commercial impact**

| Consequence class | | Release of oil [Tonnes] | ERAC /Year |
|---|---|---|---|
| 1 | Minor harm | 10 | $10^{-1}$ |
| 2 | Moderate harm | 10-100 | $10^{-2}$ |
| 3 | Significant harm | 100-1000 | $10^{-3}$ |
| 4 | Serious harm | 1000-10 000 | $10^{-4}$ |
| 5 | Major/Catastrophic harm | >10 000 | $10^{-5}$ |

The ERAC values are simple to use since they focuses on frequency and release size instead of environmental restoration time and activity level. Other advantages of such method are explained in section 5.3.

The acceptable frequency of an event can also be adjusted to special circumstances by using following correction factors:

- Distance to shore, less than 150 km [yes/no]
- Presence of vulnerable resources [yes/no]
- Water temperature, less than 15$^0$C [yes/no]

All correction factors have the same value of 0.5 which the tabled acceptable frequency should be multiplied with. For instance, two “yes” means *(Acceptable frequency)* $\cdot$ *0.5*$^2$, three “yes” means *(Acceptable frequency)* $\cdot$ *0.5*$^3$ etcetera. The value of 0.5 is a qualitative judgement, based on the fact that three yes will increase the protection requirements by about one SIL.

According to Jarnelöv (2010), all these three parameters are affecting the outcome. Distance to shore affect mammals and human recreation areas along the coast line. The mean offshore oil platform distance to shore in the Gulf of Mexico is about 50-60 km, but the Deep Water Horizon accident occurred at a distance of 77 km from shore. That example clearly stated that severe impact can occur even at great distances /7/. A rough assumption is therefore made that all offshore oil spills in range up to 150 km from the shore are causing huge environmental impact. The next correction factor is based on presence of vulnerable resources. Examples of such resources may be loss of ecosystem services like commercial fishing or sensitive fauna such as spawning areas for fishes and other sea living creatures. Even though fish are usually not affected by oil spills, their spawning areas can be harmed with devastating consequences /3/. Finally, water temperature is an important correction factor due to biodegradation of oil. A thumb rule is that the degradation process doubles every 10$^0$C. Experience from the Exxon Valdez disaster showed that cold water oil spills can cause high biological damage and even permanent damage /34/. All these correction factors are easily used, which is good when performing LOPA since them method is not supposed to be very time consuming.

## 5.3 Background of ERAC

For oil companies active on the Norwegian continental shelf, it is stated in the Management regulation that the operator shall set the acceptance criteria for major accident risk and environmental risk. However, it appears that most companies use the same criteria based on the

MIRA ERAC example table, related to environmental restoration time and maximum annual frequencies. That table is supposed to be an example based on a set of assumptions about the operational activity in the region, but has been developed into a kind of static authority in the industry. The intention of making the acceptance criteria field and region specific has not been met /49/. Furthermore, according to SINTEF (2011) these criteria are not adequate due to following reasons:

- ERAC values based on consequences such as temporal environmental recovery are attached with a high degree of uncertainty due to many influencing factors. While moving along the consequence chain the uncertainties increase as the calculation incorporates more assumptions and input parameters, illustrated in Figure 21. Furthermore, environmental recovery time are well understood by biologists, yet it appears vague to technical personnel. Acceptance criteria expressed earlier in the chain, such as maximum allowed frequency of an event, may reduce uncertainties and may be easier for operators to use and to understand.

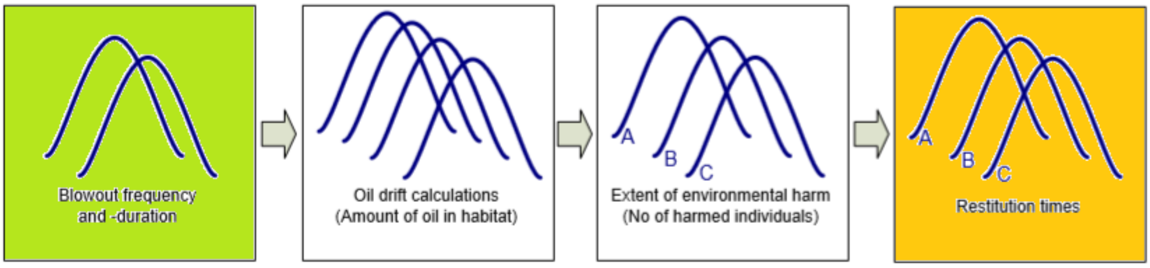


**Figure 21 the uncertainty increases along the event chain as it includes more assumptions and input parameters. The first green square represents frequency while the fourth orange square represent consequences /49/.**

- The operator has to define tolerable harm in terms of maximum proportion of time in which the environment can be affected, e.g. 5 % of the time. However, if this level is set to each consequence category, minor, moderate, significant and serious independently, the accumulated tolerable level reaches 19 %. The accumulated effect is not further discussed.
- The ERAC are based on assumptions regarding the field activity level. This makes sense with respect to equal risks in different areas. However, activity level will change over time, and from an industrial point of view it can raise questions. For instance, will a “newcomer” to an already existing field face stricter requirements than the facilities already there? Alternatively, do old facilities need to be redesigned if the number of facilities increases, in order to keep the overall field risk on an acceptable level?
- The estimated environmental risk has generally been so low that risk reducing barriers have not been required. The current ERAC does not seem strict enough.

Due to these reasons, another approach has been adopted in this thesis. The ERAC values, presented in Table 7 are supposed to be stricter and easier to use, since the ERAC are based on maximum allowed frequency and spill size instead of temporal environmental recovery and field activity level.

## 5.3 CRAC

The commercial risk acceptance criteria (CRAC) are of great importance for oil producers, since it affects their long-term survival as a company. Several oil spill disasters, such as the Deepwater Horizon accident, shows that the cost of an accident can sum up to billions of dollars. Such a cost is a heavy burden, even for a huge global oil producer.

In this thesis, the commercial cost is divided into two main classes:

- Clean-up cost
- Compensation of damages, i.e. third party claims.

The clean-up cost is highly dependent on the accident characteristics, such as the type of oil, location of the oil release, the characteristics of the affected area and the quantity of the oil release /14/. Average clean-up costs for tanker oil releases, due to different regions, are shown in Table 8. Generic values for third party claims are harder to estimate. However, it can be assumed that the third party claims are related to the socioeconomic costs and the environmental losses. According to Edresen et al (2006), these factors can be estimated to be a ratio of 1.5 the clean-up cost for oil tanker releases. This estimate is used also in this thesis, even though there are uncertainties coupled with transferring a value from one industry into another.

**Table 8 Clean-up cost per region (2006 $) /14/.**

| Region | Clean-up cost per tonne [$] |
|---|---|
| Europe | 13 100 |
| North America | 24 000 |
| South America | 3 800 |
| Africa | 3 900 |
| Middle east | 1 300 |
| Asia | 33 500 |
| Oceania | 6 900 |

In this thesis, the CRAC is set so that a major commercial loss of 10 billion dollars is accepted once in a million year, $10^{-6}$/year. The same value is commonly used among several large oil producers. The other consequence classes are linearly correlated to that value, as shown in

Table 9. Oil release cost per tonne is divided into different regions due to various clean-up costs.

**Table 9 CRAC for commercial impact**

| Consequence class | | Commercial losses [$10^6 \cdot$ $] | CRAC / Year | Corresponding release quantity of oil per region [$10^3 \cdot$ Tonnes] | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | | | | Europa | North America | South America | Africa | Middle east | Asia | Oceania |
| 1 | Minor cost | 10 | $10^{-2}$ | 0.03-0.3 | 0.02-0.2 | 0.046-0.46 | 0.1-1 | 0.3-3 | 0.012-0.12 | 0.058-0.58 |
| 2 | Moderate cost | 10-100 | $10^{-3}$ | 0-3-3 | 0.17-1.7 | 0.46-4.6 | 1-10 | 3-30 | 0.12-1.2 | 0.58-5.8 |
| 3 | Significant cost | 100-1000 | $10^{-4}$ | 3-30 | 1.7-17 | 4.6-46 | 10-100 | 30-300 | 1.2-12 | 5.8-58 |
| 4 | Serious cost | 1000-10 000 | $10^{-5}$ | 30-300 | 17-170 | 46-460 | 100-1000 | 300-3000 | 12-120 | 58-580 |
| 5 | Major cost | >10 000 | $10^{-6}$ | >300 | >170 | >460 | >1000 | >3000 | >120 | >580 |

# 6. Identification of subsea protection layers

Safety barriers are important tools in order to reduce environmental, commercial and safety related risk. The first section in this chapter comprises a generic description of different protection layers and explains important concepts. The next sections, 6.3 to 6.7, provide a subsea protection layer identification, where protection layer functions are described and possible LOPA credit is discussed. The risk identification has been performed by studying various kinds of literature.

In this thesis, LOPA credit is defined as the protection layers effect on the generic failure frequency. Most IPLs will decrease failure frequency and therefore get a LOPA credit less than 1. However, since some PLs are already incorporated in the generic subsea system design, lack of such a PL may result in higher risk and a LOPA credit higher than 1. A value higher than 1 actually means increased risk and can be seen as a form of "design punishment".

## 6.1 Safeguards

Safeguards are an important tool in order to reduce risk. A safeguard is defined as a device, system or action that would either interrupt a chain of events leading to an unwanted consequence or mitigate the consequence /6/. Examples of different safeguards functions are:

1. Eliminative: Better process design, e.g. inherently safe design due to pressure build up;
2. Preventive: Alarms and safety instrumented systems;
3. Control: Basic processes control systems, such as a choke controlling the flow;
4. Mitigation: Fire walls, dykes, sprinkler systems;
5. Emergency response: Plant emergency response and community emergency response.

According to the LOPA-guidelines of a big oil producer, risk reduction measures should be prioritized according to their effectiveness. Eliminative measures, such as changes in process design, are considered as the best option while relying on emergency response is considered as the last line of defence. A safeguard does not need to meet the same requirements as Independent Protection Layers (IPLs), but some of them can be credited when to determine the overall system risk.

## 6.2 Independent Protection Layers

An Independent Protection Layer (IPL) is a device, system or action that interrupts series of events leading to an unwanted consequence. If all IPLs in a scenario fail to act, the undesired consequence will occur. Just one IPL has to acts as intended to avoid the unwanted outcome, as shown in Figure 22. An IPL has to meet the following criteria /6/:

- Effective: An IPL has to provide a minimum of a 10-fold risk reduction and provide a high degree of availability, more than 90 %. Effectiveness is quantified as PFD, probability of failure on demand, which refers to the probability of an IPL not performing its required task. The PFD is intended to take all failure modes into account, including factors such as human errors etc. PFD is in range zero to one, where a lower value means larger risk reduction.
- Independent: The IPL has to be independent, so that failure of one IPL will not affect another. Nor is the occurrence of an initiating event or its consequence allowed to affect the IPLs ability to operate as intended. The IPL also needs to be independent of any component already credited for the same scenario. The only exception made is for common logic servers due to reliability close to zero. Sensors and final elements are usually the dominating failure factors.
- Auditable: The assumed effectiveness must be capable of validation, for instance by testing, documentation and review.

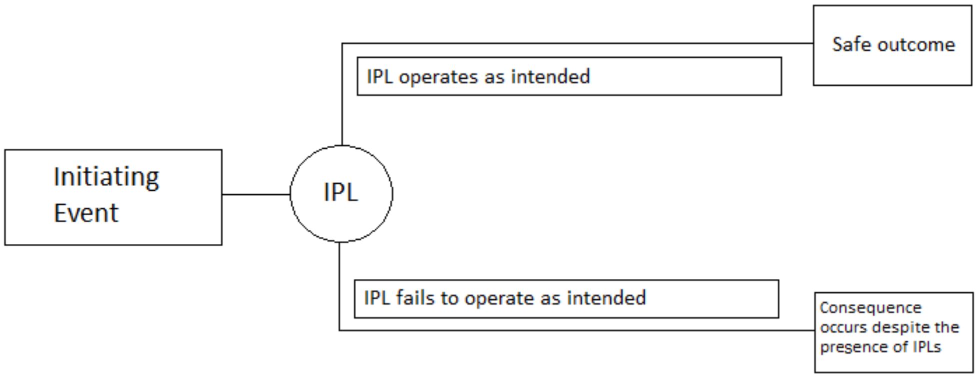


**Figure 22 Effects of IPL success and IPL failure (Illustration: Christoffer Clarin)**

The biggest difference between an IPL and a safeguard is that an IPL must be auditable. Safeguards cannot be quantified in the same way due to lack of data or too much uncertainty. Not all safeguards are IPLs, but all IPLs are considered as safeguards. Examples of safeguards not classified as IPLs are emergency response and facility evacuation. IPLs can be divided into:

- Active or passive
- Preventive or mitigating

An active IPL moves from one state into another in response to a change in process activity. Such a change can for example be an abnormal change in pressure, or a signal from another source such as human action, leading to closure of a shutdown valve. A Safety Instrumented system (SIF) normally comprises some kind of sensor, a decision making process and an action, as shown in Figure 23. Examples of an active IPL is an instrumented systems, such as basic process control systems (BPCS), SIFs, deluges and fire fighting mitigation systems, pressure relief devices, vendor installed safeguards or operator actions /6/. A vendor installed safeguard is an equipment built-in function which prevents equipment failures to cause external damage.

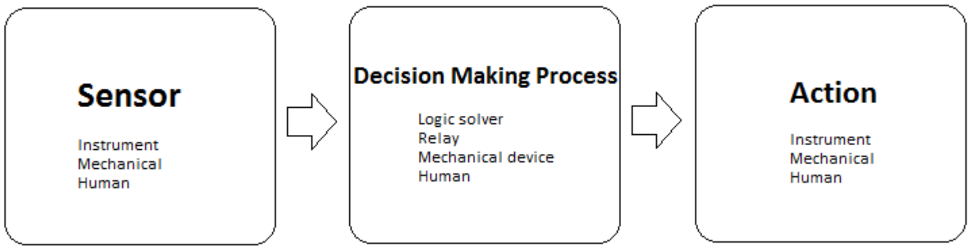


**Figure 23 Show the basic components of an active IPL (Illustration: Christoffer Clarin)**

Passive IPLs are, unlike active IPLs, not required to take any action to achieve its risk reducing function. Examples of passive IPLs can be tank dikes, blast walls, fireproofing etcetera. Also inherently safe design can be considered as passive IPL, even though it is supposed to eliminate the risk. Inspection and maintenance have to ensure that process changes do not affect the effectiveness of the inherent design properties and therefore the inherent design cannot be seen as 100 % reliable. An inherent design has a PFD, just as the rest of the IPLs /6/.

Since risk is defined as a combination of the probability of an event to occur and the severity of its consequence, risk can be reduced in two ways. Some IPL functions can prevent a consequence from occurring in the first place and are classified as preventive. Mitigating IPLs on the other hand reduces risk by lowering the consequence. An example of a preventive IPL can be a preventive SIF closing a valve due to pressure build up, while a typical mitigating SIF stops the hydrocarbon flow after the incident has already occurred, e.g. due to leakage.

## 6.3 Inherently safe design

Inherently safe designs are passive and preventive safeguards of particularly importance if the consequences of a failure are considered high. An inherently safe design avoids hazards instead of controlling them. It is therefore recommended that safer design properties shall be incorporated in order to reduce reliance on safety systems and operational measures, wherever possible. In subsea context, one inherently safe design measure has been identified. Note that even though an inherently safe design is supposed to eliminate the risk, such an IPL is dependent on maintenance and inspection operations and has a PFD due to human factors.

### 6.3.1 Pressure safe design

If a subsea system is not designed to withstand full wellbore pressure, a stopped flow during production can cause pressure build up, whereupon dangerous situations can arise. Typical failure mechanisms are critical plugs or topside emergency shutdown (ESD) functions. The pressure build up failure fraction, without any protection layers or pressure safe design available, is considered as a substantial threat. When dividing the critical plug frequency for pipelines and manifolds by the total leakage frequency, it results in a failure fraction of 50 %. However, a pressure safe design significantly reduces that failure frequency. The suggested LOPA credit for an inherently safe design is, according to common industry praxis, set to 0.01 /6/.

LOPA Credit: 0 - 0.01

## 6.4 Robust design

A robust design can significantly decrease failure frequency. Design measures are preferable, since SIS is not supposed to be a sticky plaster over poor process design. In this section, three robust design measures have been identified.

### 6.4.1 Corrosion protective design

Corrosion contributes to 40 % of all North Sea pipeline leakages. Internal corrosion is the major problem, since $CO_2$, $H_2S$ and microbiological induced corrosion contributes to thinning of the subsea unit walls. External corrosion is usually not a big problem thanks to less contact with chemicals and the use of corrosion protective coating /3,9/.

Corrosion is an electrochemical process where anodic and cathodic electrochemical reactions occur simultaneously. Anodic reactions involve oxidation of metal to ions, while a cathodic reaction involves reduction. However, if additional electrons are continuously added from an external source, then the anodic reaction will decreases and lower the corrosion rate /17/.

All metallic subsea structures can be protected by two different methods. The first method is the impressed current method which means that the anode receives current from an external power source. Large areas of the metallic structure, e.g. the pipeline, can be protected because of the high driving voltage. The power supply may be placed remote from the structure. If sacrificial anodes are used instead, they need to be placed close to the structure being protected. A sacrifice anode continues to provide electrons to the more electropositive steel until it has been consumed /17/.

A good corrosion protection design is assumed to be a kind of robust design. Theoretically, a high reliable corrosion protection would be able to almost eliminate the failure rate out of corrosion. However, since there are no data available regarding corrosion protective design effectiveness, or which types of corrosion protection already included in the base failure frequency, no LOPA credit can be recommended.

### 6.4.2 External Impact Protection

External impact incidents, such as dropped objects or trawling activity, are dominating initiating causes in the North Sea. These incidents are less frequently occurring in the Gulf of Mexico (GoM) since all pipelines are burrowed /9/. In other words, there are safety measures to be made in order to decrease the number of external impact incidents. For subsea systems, two possible protection measures have been identified, the use of templates and buried and/or trenched pipelines.

- Buried and/or trenched pipelines: In the GoM, all pipelines are burrowed. These measures are probably the reason to why impact/anchors represents 42 % of all failures in the North Sea, while only 13 % in Gulf of Mexico /9/. However, even In North Sea the majority of all pipelines have some kind of external impact protection, either as trenching (lowering) or burial (covering). No significant differences have been found between trenched and buried pipelines /57/. Out of that fact, the recommended LOPA credit range between 0.2 to 2.0. A value closer to 0.2 is recommended if the whole pipeline is protected.

  LOPA Credit: 0.2 – 2.0

- Templates: In the Norwegian part of North Sea, most manifold installations are protected by templates. These installations protect vital subsea equipment from external loads, except extremely heavy ones such as dropped Christmas trees[2]. According to OGP (2010), the failure frequency of a pipeline section, where loads from trawls possess a threat, can be increased by a ratio of five times the generic failure frequency. Since external impact incidents stands for about one quarter of all incidents, the use of templates are assumed to provide a tenfold protection against external impact. However, since most systems already use templates, it is already included into the base failure frequency. Instead of a credit, the absence of a template should be "punished" with a "LOPA credit" in range 1-10, due to surrounding circumstances.

  LOPA Credit: 1.0 - 10.0

### 6.4.3 High quality steel

Pipeline casing material can be categorized as "high" or "low" grade steel, where API steel grades less than X48 is considered as low grade and X52 to X80 plus is considered as high grade /57/. No clear trend has been observed between these two categories in open sea zone, but within the safety zone high steel pipelines seem to have a tenfold decrease of external impact failure frequency /57/. Constantly, a LOPA Credit of 0.1 can be applied within the safety zone.
For instance, if the pipeline is 1.0 km long, the LOPA credit for high grade steel can be $(0.5 \cdot 0.1 + 0.5)/1 \approx 0.6$. Therefore, LOPA Credit can be taken into account until a pipeline length longer than 5 km, as shown in Table 10. However, the LOPA expert group can decide to use LOPA credits even for longer pipeline distances.

**Table 10 Recommended LOPA Credit for high quality steel pipelines**

| Pipeline length [km] | LOPA Credit [≈] |
|---|---|
| 0.5 | 0.1 |
| 1.0 | 0.6 |
| 5.0 | 0.9 |
| 10.0 | >0.9 (0.9-1.0) |

LOPA Credit: 0.1 – 1.0

[2] Morten Nilstad Pettersen, Senior Safety Consultant at Oilconx Risk Solutions (ORS)

## 6.5 Safety Instrumented Systems

A SIS, is a combination of sensors, logic solver and final elements which together performs a SIF in order to prevent or mitigate an unwanted consequence. A SIS consists of one or several SIFs, and each SIF will have a PFD depending on type- and number of sensors, logic solvers and final elements. The PFD is also affected by the time interval between periodic functional tests, where a longer interval leads to an increased PFD. To increase the SIS reliability, several design measures can be performed /6/:

- SIF shall be functionally independent from the BPCS. These two systems shall not share any common sensors, logic solvers or final elements.
- The system logic solver usually comprises multiple redundancies due to several processors, redundant power supply and human interface. The logic solver PFD is often close to zero.
- The design of a SIS often comprises component redundancy, e.g. several sensors or multiple final elements.
- SIS can use voting system in order to avoid spurious trip of the process. For instance, 2oo3 voting means that two sensor out of three must be stimulated in order to activate the SIF.
- The use of self-diagnostic to detect and communicate instrument faults can reduce the mean repair time, and thereby also reduce overall SIF PFD.
- SIS often uses a de-energized to trip philosophy. For example, if the communication line from the topside facility and a subsea valve is lost the valves will automatically close.

In subsea context, two active and preventive SISs have been identified, the Production Shutdown (PSD) system and the Emergency Shutdown System (ESD). Both SISs are further described below.

### 6.5.1 Subsea PSD-system

The purpose of the subsea PSD-system is to control abnormal operating conditions in order to prevent unwanted hydrocarbon releases. That includes stopping hydrocarbon flow by shutting down process and utility equipment. A PSD system typically depends on hydraulic power and instrumented air /49/. A schematic picture of a subsea PSD is shown in Figure 24. However, due to de-energize to trip philosophy, subsea valves will automatically close if the umbilical connection is lost. Any system failure will lead to safe state[3]. The system is not standard in subsea systems, but may be added if the risk is considered high. A subsea PSD-system has two main functions:

*High Pressure Trip*: A High Pressure (HP) trip High Integrity Pressure Protection System (HIPPS), is an active and preventive protection layer which can be advantageously used if the subsea system is not designed to withstand full wellbore pressure. For example, if the export pipeline is blocked, a HIPPS can stop the flow so that the pressure design limit is not exceeded. One of the most common outlet source blockages occurs from plugs or topside ESDs. Topside ESDs stop the hydrocarbon flow and may lead to subsea pressure build up in the same way as a plugged pipeline. Topside ESDs shall therefore automatically activate a subsea PSD function, so that the subsea PSD-system does not fully rely on subsea pressure transmitters. A link between topside ESD and subsea PSD results in additional system redundancy /45/.

*Low Pressure Trip*: The HIPPS can also be designed to react on sudden pressure drops, which may be an indication of major subsea leakage. In such case, the protection layer is considered active and mitigating since the accident has already occurred. The SIF can be automatically or manually activated by a ROV.

An overall picture of a subsea production system with a HIPPS is shown in Figure 25. The credit taken for a PSD HIPPS depends on the SIL classification which is varying in range SIL1 to SIL3.

[3] Jorge Martires, Senior Safety Consultant at Oilconx Risk Solutions (ORS)

However, it is not recommended to give SIL3 credit for a preventive HIPPS. Even though HIPPS are unusual, some of them may are probably included in the base failure frequency. A better interval would in this case range between 0.001 – 1.0.

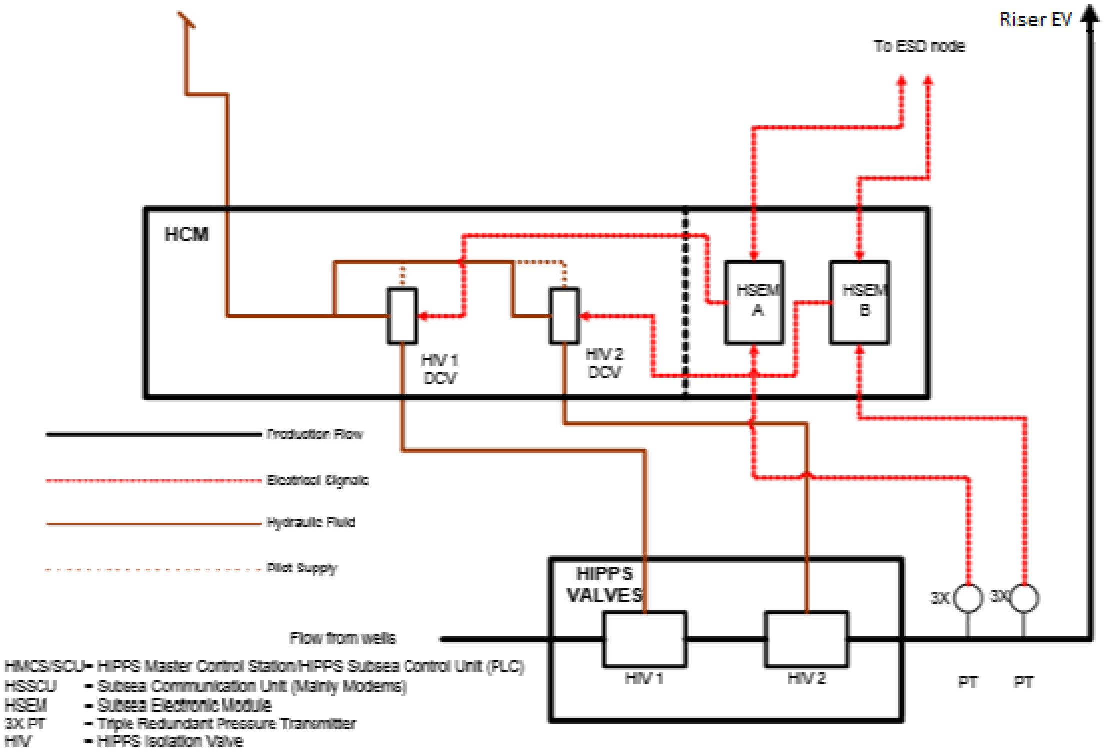


**Figure 24 Show simplified HIPPS schematic /45/.**

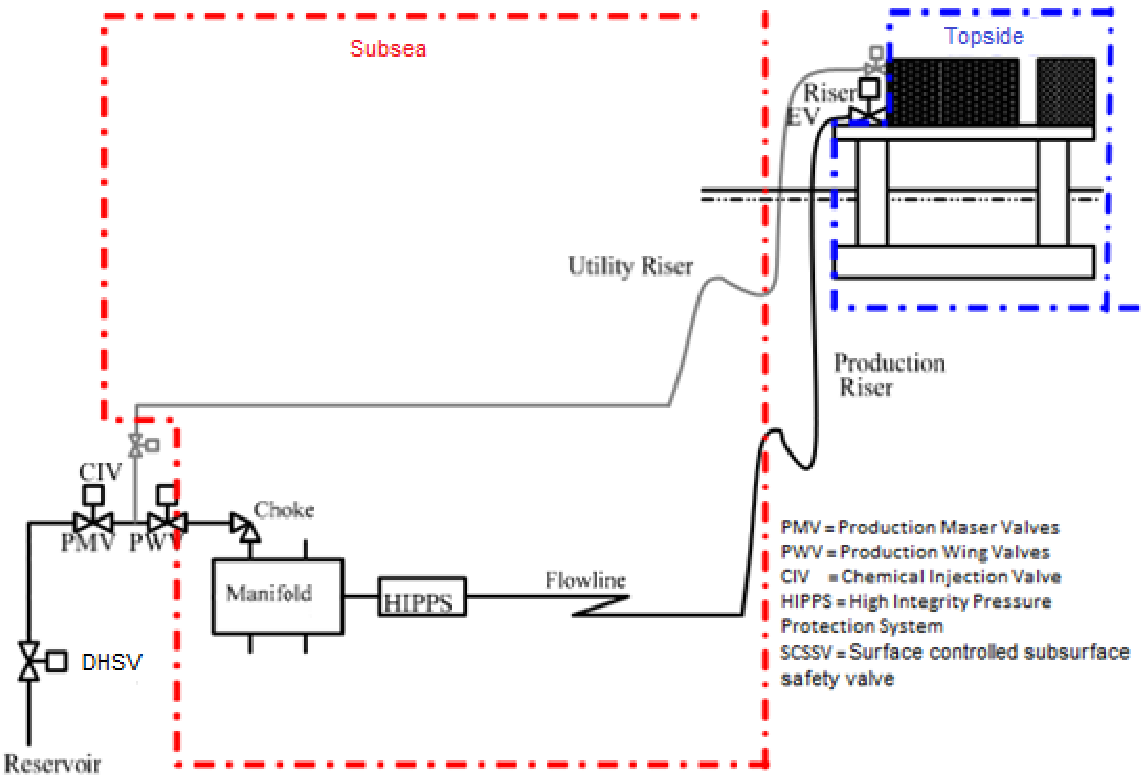


**Figure 25 Show an overall picture of a subsea production system with a HIPPS /45/**

## 6.5.2 Subsea ESD-System

The purpose of an ESD is to prevent escalation of abnormal condition and to prevent unwanted consequences from occurring. The SIS is considered as active and preventive or active and mitigating, since it can be initiated either before or after an incident has occurred. The ESD system shall be independent, but can share interfaces with other systems such as PSD, F&G and flare/vent system. An ESD can be activated automatically or manually by operators or ROVs[4]. The ESD is performed according to a predetermined hierarchical scheme, as illustrated in Figure 26. Note that the scheme can vary between different platform and different countries /49/.

In the OLF 070 guideline there are two main ESD-systems presented, “Isolation of riser” and “Isolation of subsea well”. LOPA Credit for these ESD function depends on its SIL-rating, which can vary in range SIL1 to SIL3. Each SIF is further described in the next sections.

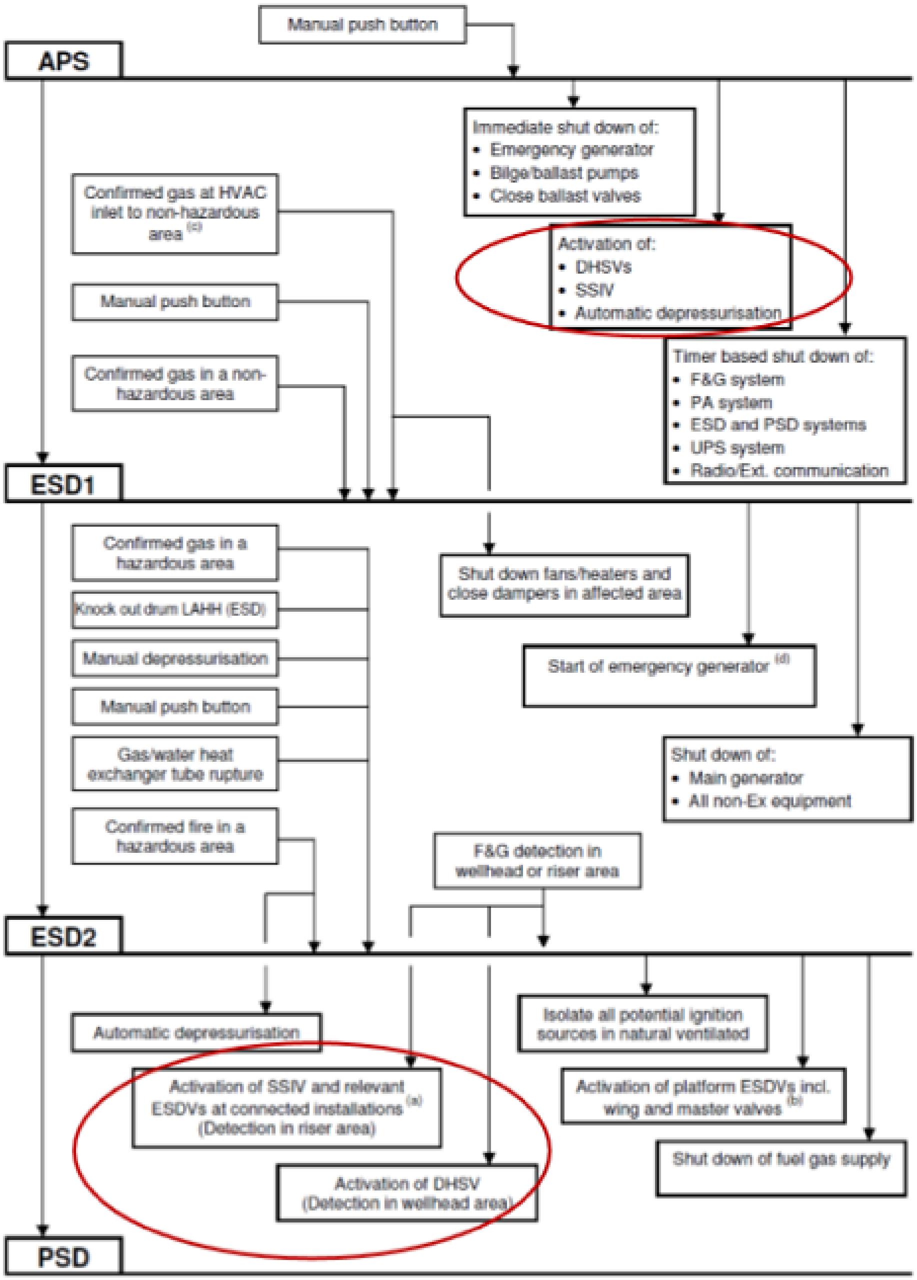


**Figure 26 Show an ESD hierarchy /49/.**

[4] Morten Nilstad Pettersen, Senior Safety Consultant at Oilconx Risk Solutions (ORS)

#### 6.5.2.1 Isolation of riser

Isolation of the riser occurs on demand from the ESD system. The process is initiated by an ESD node, e.g. on hydrocarbon leak detection or fire detection. The safe state of the process is defined as a closure of the riser emergency shutdown valve.  If high reliability should be achieved, it may be relevant to consider use of two parallel Emergency Shutdown Valves (ESDVs). The system is normally energised so that loss of signal or power will cause automatically closure of the ESD valve /45/.The SIF is illustrated in Figure 27.

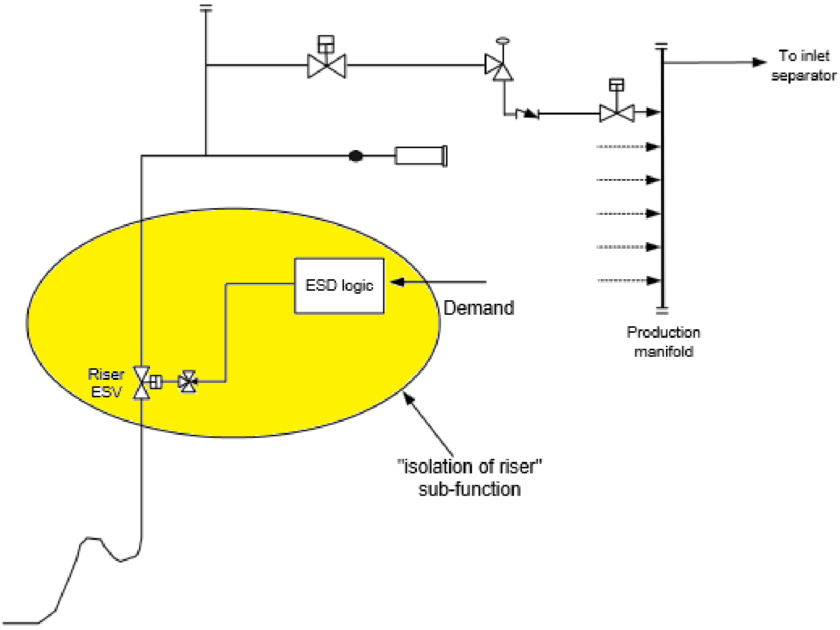


**Figure 27 Show the isolation of riser function /45/**

#### 6.5.2.2 Isolation of subsea well

The subsea well and Xmas tree comprises several valves considered as IPLs. Of all subsea IPLs, these are the ones closest to the hydrocarbon source. A safe state occurs when these valves are shutting in the well. The “Isolation of subsea well” SIS consists of /49/:

- Topside/onshore located ESD node
- Topside/onshore located ESD hydraulic bleed down solenoid valve in HPU
- Topside/onshore located ESD electrical power isolation relay in EPU
- Production Wing Valve, PWV, including actuators and solenoids
- Chemical Injection Valve, CIV, including actuators and solenoids
- Production Master Valve, PMV, including actuators and solenoids
- Down hole safety valve, DHSV, including actuators and solenoids

More information about subsea wellheads and Xmas trees are found in section 2.9.1.

An Electrical Power Unit (EPU) and/or a Hydraulic Power Unit (HPU) procures the necessary power to perform a well isolation action. All valves should be hydraulically fail safe, e.g. the valves should be closed if communication is lost. Any Xmas tree isolation valve is able to isolate the well. However, if the event is the highest demand of ESD (Figure 26), the well should be isolated by the DHSV /45/. The isolation process could be automatically activated or manually activated by an operator or a ROV, except the DHSV which cannot be reached by ROVs. The “Isolation of well” SIF is shown in Figure 28.

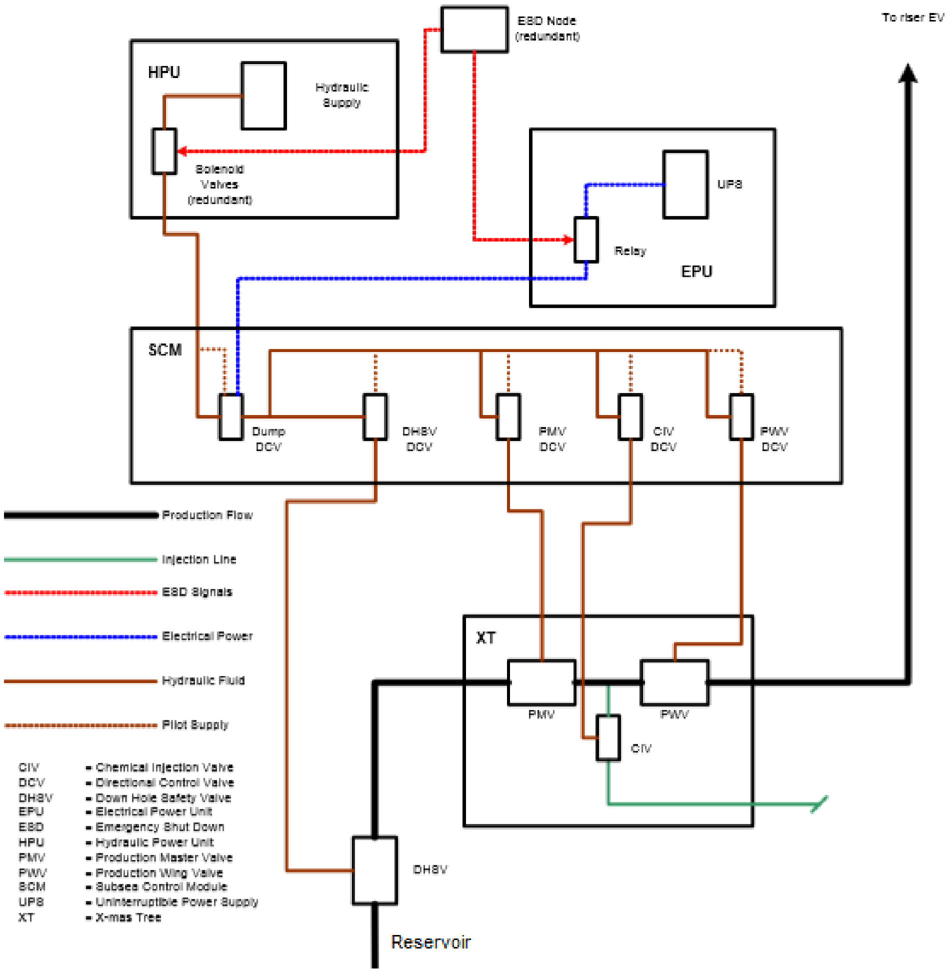


**Figure 28 show the isolation of well function /45/.**

## 6.6 Basic Process Control System

The Basic Process Control System (BPCS) is considered as an active and preventive and active and mitigating protection layer. In subsea context, the BPCS manage one or several chokes in order to control hydrocarbon flow. Chokes are usually a part of each Xmas tree or in direct connection to the Xmas tree, as shown in Figure 29. The BPCS function is to control the day-to-day plant operation, but can as well provide an IPL functions if necessary. The IPL function can be performed in three different ways /6/:

- Continuous control action: The BPCS performs continuous control action in order to keep the process in a safe state;
- State controllers: Logic solvers and alarm trip units can identify abnormal conditions and send a message to an operator, usually as an alarm signal. The operator can take proper actions in order to avoid the disaster, such as initiate a PSD.
- State controllers: Logic solvers and control relays can take automatic action, e.g. trip the process in order to move it into a safe state.

The BPCS is normally considered as a weak IPL due to little redundancy in the components, limited testing capability and limited security against changes into program logic. Human error, such as bypassing alarms and interlocks or incorrect response to alarms , can degrade the BPCS reliability even more /6/.

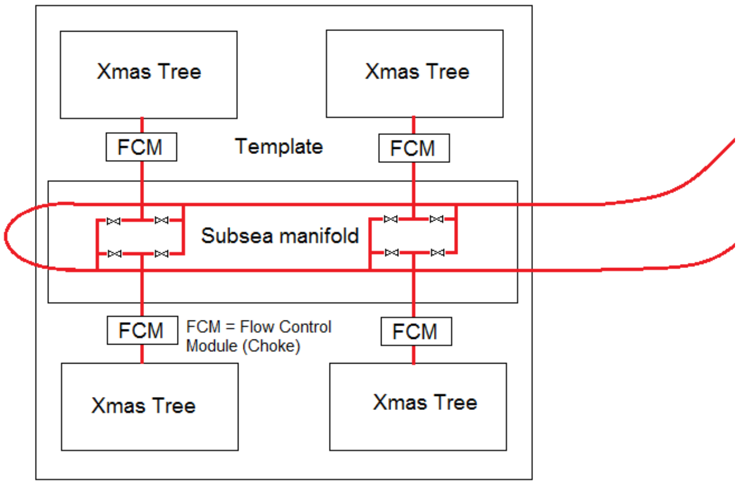


**Figure 29 show flow control modules in a manifold/template structure (Illustration: Christoffer Clarin)**

If credit shall be taken for the BPCS it must be ensured that the chokes will not collapse due to full wellbore pressure. Depending on the BPCS reliability, the number of chokes, the quality of the chokes and the grade of human response, the LOPA credit can vary in range 0.1 to 1.0. A high quality choke with an automatic shutdown function is considered to be closer to 0.1. However, according to IEC 61511 a LOPA credit less than $10^{-1}$ cannot be claimed.

LOPA Credit: 0.1 – 1.0

## 6.7 Human IPLs

A human IPL involves an operator to take appropriate actions in response to an alarm, in order to prevent or mitigate an unwanted consequence. If the loop is considered as a chain of events, the human action is usually the weakest link, see Figure 30. The human reliability in the industry usually ranges between $1 \cdot 10^{-2}$ to 1.0, but according to common LOPA practice the PFD for the whole loop shall not be given credit less than 0.1 /6/. Human reliability can be determined by different Human Reliability Analysis, such as the SPAR-H method /56/.

In subsea context, four different human protection layers have been identified. If these shall be considered as IPLs must be determined from case to case. There is a probability that they share final element with other protection layers, such as SISs and/or BPCS.

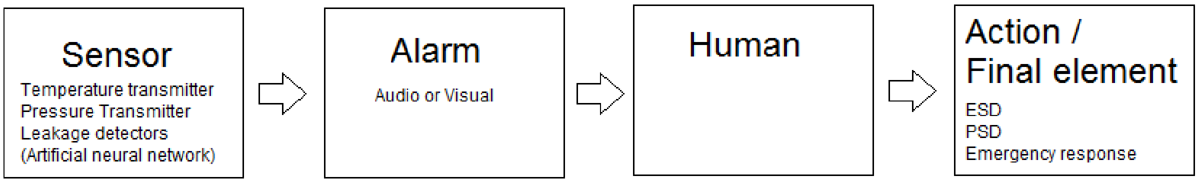


**Figure 30 Show a simple human IPL block diagram (Illustration: Christoffer Clarin)**

### 6.7.1 Erosion sensors

Erosion is an abrasion process that occurs when sand and/or slurry is transported through the pipelines. The erosion rate is proportional to the mass of sand and the flow rate. Erosion is usually not a problem if the flow velocity is less than 3 m/s /3/. There are several techniques to measure erosion rate, e.g. remote visual inspection used to assess specific tubes, erosion based sensors measuring metal loss caused by solid particles, acoustic based sensors monitor the noise of sand impact or ultrasound inspection techniques /21/. However, erosion is not a main failure mechanism in subsea systems and there are insufficient data about sensor efficiency. Therefore, no LOPA Credit can be recommended in this case.

### 6.7.2 Abnormal Pressure- and Temperature Alarm

Several pressure and temperature transmitters are integrated into the subsea system. If an abnormal condition occurs, the operators shall be noted by an alarm so that proper actions can be taken. Since most subsea systems already include this kind of protection layer, it is assumed that LOPA credit is already included in the base failure frequency. However, if the evaluated system does not have such a protection layer, the failure frequency shall be increased by a ratio of 1-10.

LOPA credit: range 1-10

### 6.7.3 Leakage detectors

Most leakages are small. Corrosion and bad installation is the main reasons for leakages, followed by impact, erosion, non-metallic seal degradation and failure of valve seats. Weak spots where leaks may occur are connections, connectors, flanges, seals, valves and welds. Generally, gas leakages are easier to detect than crude oil leakages /10/.

The purpose of leak detection systems is to achieve early warning of small and medium sized leakages in order to perform corrective actions. There are several techniques to detect such leakages, but they perform differently due to varied conditions. The trend in Norway seems to be adding permanent leak detection systems, as in Figure 32. However, the international trend points towards increased use of mobile detection units, such as ROVs with detector abilities. For better leak detection confidence, several leak detection principles can be used simultaneously. The detection principles can be divided into /10/:

*Area coverage detection*: An area coverage detector has the capability to place the leakage relative to its position.

*Point sensors*: A point sensors are not able to determine the location of a leak. Therefore, point sensors may be suitable to place near subsea structure high risk leak points.

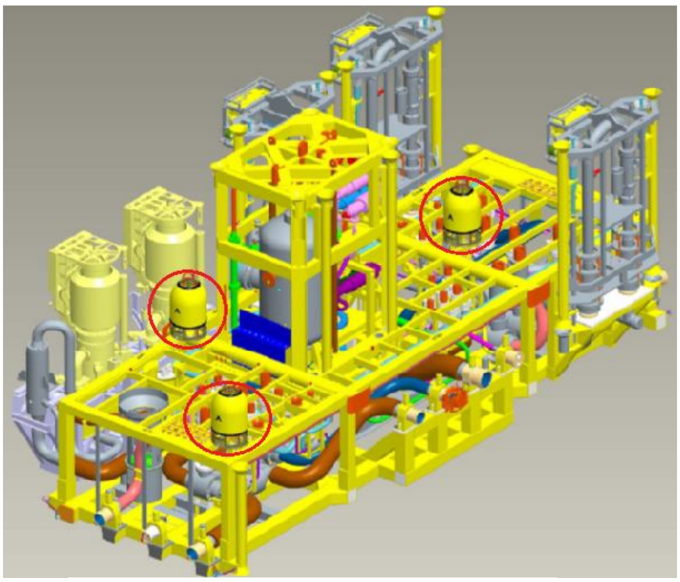

**Figure 31 show three cone shaped leak**

*Mass balance*: The mass balance is based on monitoring the differential pressure between two or more pressure transmitters. If a leak is above 5 % of the total flow, the leak will be detected. The economical expense is considered small, since already existing BPCS transmitters can be used.

All three detector types need to access the control system for continuous subsea monitoring. The system is considered as monitoring systems and potentially a human IPL. Since the system is considered as part of the BPCS, or as a human IPL, the LOPA credit can never be less than 0.1.

According to statistic, the fraction of identified leaks which have not been detected by technology is about 30%, calculated by $X/(X+Y)$. However, the statistic is uncertain due to the large amount of leakage event without further details, as shown in Figure 32. The LOPA credit shall thereby be used with caution.

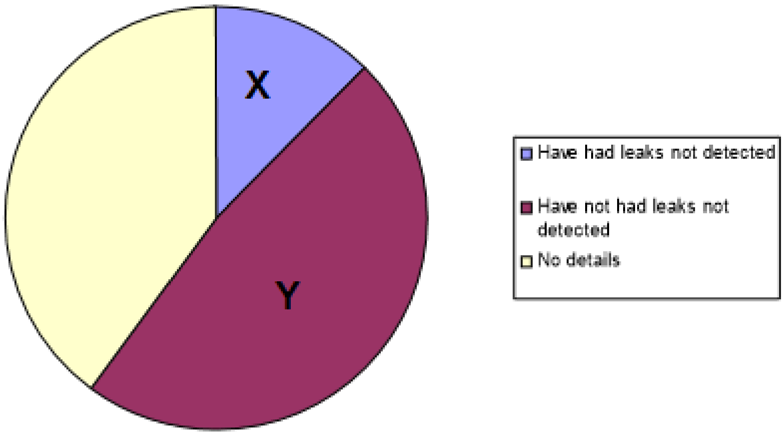


**Figure 32 Show the leakages detected by leakage detectors from 40 North Sea fields /10/.**

The human action is also an important factor, which LOPA credit differs in range 0.1 to 1.0. If combining the LOPA credit for detection (0.3) and human action (0.1), the total LOPA credit for a leakage detector system ranges in between 0.4 to 1.0.

LOPA Credit: range 0.4 – 1.0

### 6.7.4 Artificial neural network warning

Artificial Neural Network (ANN)is a computerized model inspired by animal central nervous system which allows machines to learn and recognize pattern. The advantage of such a model is that it measures several outputs in order to recognize deviation. For example, in a subsea pipeline, the pressure-, flow- and temperature sensors may indicate normal conditions independently. However, if all data output is interpreted together, it may indicate abnormal conditions at an earlier stage. Such an early warning may indicate a need of maintenance and inspection operations, so that dangerous fault can be prevented at an early stage. To the best of the author's knowledge, no artificial neural networks are yet in service, but with further research and development it may be the future of advanced subsea failure detection. Since no artificial neural network warning systems is in service, ANN is not taken further into consideration in this thesis.

## 6.8 Protection layer summary

In total, 14 different protection layers have been identified. In 11 of these cases, there are enough data for taking LOPA credit. All protection layers are summarized in Table 11.

**Table 11 Show a summary of all identified protection layers and the LOPA Credit**

| Protection Layer | Function | | LOPA Credit |
|---|---|---|---|
| Inherently Safe Design | | | |
| 1 | Pressure Safe Design | | 0.01 |
| 2 | Corrosion Protective Design | | Lack of data |
| 3 | Buried and/or trenched pipelines | | 0.2-2.0 |
| 4 | Template | | 1.0-10.0 |
| 5 | High grade steel in pipelines | | 0.1-1.0 |
| Safety Instrumented Systems | | | |
| 6 | Subsea PSD | High Pressure Trip, HIPPS | SIL1-SIL3 |
| 7 | Subsea PSD | Low Pressure Trip, HIPPS | SIL1-SIL3 |
| 8 | Subsea ESD | Isolation of riser, SSIV | SIL1-SIL3 |
| 9 | Subsea ESD | Isolation of subsea well | SIL1-SIL3 |
| Basic Process Control System | | | |
| 10 | Choke | | 0.1-1.0 |
| Human Protection Layer | | | |
| 11 | Erosion Sensors | | Lack of data |
| 12 | Abnormal Pressure and Temperature Alarm | | 1.0-10 |
| 13 | Leakage detector | | 0.4 – 1.0 |
| 14 | Artificial Neural Network Warning | | Lack of data |

# 7. The LOPA-model

In this chapter, the risk assessment and SIL-determination process are described. Since the risk is defined as a combination of frequency and consequence, a system specific failure frequency and consequence are being estimated. In this LOPA model, the consequence is divided into environmental-, commercial- and safety impact.

As opposed to a standard LOPA based on generic initiating cause frequencies, this model takes basis in a generic leak frequency. In order to adjust the generic frequency into a specific subsea system, several correction factors based on engineering judgement are being used. The LOPA-method can be divided into four main steps, which are further described below. A schematic picture of the overall LOPA-methodology is presented in Figure 33.

- *System specific failure frequency*: During step 1, the failure frequency for the specific subsea system is estimated. First, a base failure frequency has to be adopted. The base failure frequency is a strictly generic value determined according to chapter 4. However, in order to better reflect reality, system specific properties such as incorporated protection layers and surrounding circumstances have to be taken into account. This is achieved by using a modified correction factor ($M_{CF}$) determined by the LOPA expert group. The modified correction factor is multiplied with the base failure frequency by using a LOPA worksheet, in order to find out the total subsea system specific failure frequency.
- *Consequence analysis:* In this thesis, environmental and commercial impact is assumed to correlate to the quantity of the hydrocarbon release. The quantity of the hydrocarbon release can be calculated by multiplying the massflow by the oil spill duration time. The massflow is a function of differential pressure, hole size and friction loss, while duration time depends on mean repair time and other circumstances.
- *Safety risk:* Several platform specific factors are affecting the safety impact of an accident, such as present protection layers, the amount of people on the platform, presence of free fall lifeboats, ignition probability etcetera. How these factors affect the consequences of an accident is for the LOPA group to decide. Safety risk is a combination of hydrocarbon release frequency and the numbers of fatalities and injured people.
- *SIL-determination:* Finally, the SIL-determination is performed by comparing the subsea system specific risk with risk acceptance criteria. If the needed risk reduction (RR) is less than 1, no further safety measures have to be implemented.

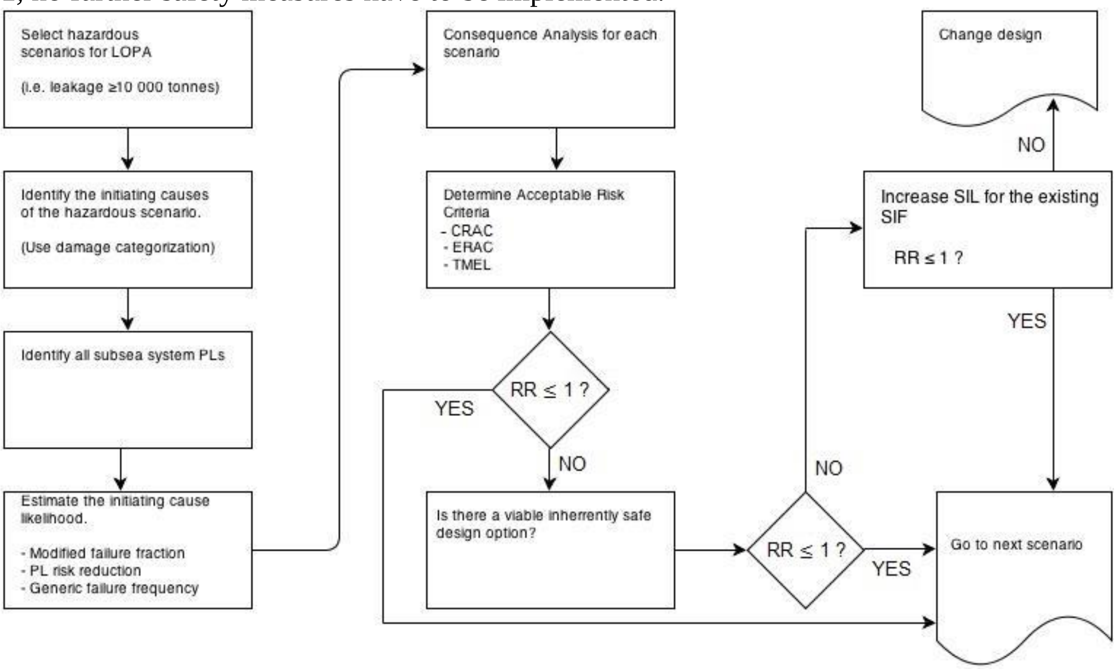


**Figure 33 Schematics of LOPA-methodology (Illustration: Christoffer Clarin)**

## 7.1 Subsea specific failure frequency

In a specific subsea system, the failure frequency will not adopt completely generic values. The failure frequency depends on several circumstances which must be taken into account, such as ship traffic density, weather conditions, subsea system design and presence of safety barriers. In order to estimate a specific correction factor, the worksheet in Table 14 and Table 15 can be used as guidance. The determination process can be divided into two steps:

- First of all, the user of the model simply has to multiply the base failure fraction by a qualitative engineering estimate. Since the base failure fraction is grounded on generic failure frequency from pipelines in the North Sea, the system specific failure distribution will certainly differ since no real system can be completely generic. How much the specific system differs is up to the LOPA expert group to estimate. However, some recommended intervals are being included into the tables. These recommended values are based on a comparison between offshore pipeline failure fraction in the North Sea and the Gulf of Mexico. The value inside brackets is the multiplication factor to be used if transferring generic data from one region into another, i.e. from North Sea to GoM. It is important to understand that these intervals and inside bracket values are only suggestions in order to support the qualitative judgement of the LOPA expert group and do not necessary have to be followed.

- Secondly, LOPA credit for all present protection layers shall be taken into account. The "Base Failure Fraction" and the "Frequency Correction Factor" are multiplied by the LOPA credit of all affecting protection layers. The result from each category is then being summarized in order to find out the modified correction factor for each hazard scenario.

When the model was created, some assumptions were made. First of all, the base failure distribution was based upon pipeline failures leading to leakages in the North Sea. These values are assumed to be applicable even at other subsea equipment, such as Wellhead and Xmas tree, manifold and riser installation. According to the statistic, corrosion and external impact seem to be dominating failure elements. Other important failure categories comprise material damage, structural failures, and other failures /9/.

In this thesis, all identified initiating causes have as much as possible been merged into five failure categories, originally used by DNV (2009). However, slight modifications had to be made in order to take all identified initiating causes into account. The category "other" was separated into "natural hazards" and "additional hazards" by using comparable pipeline failure statistic of damage not leading to any direct leakages. The "natural hazard" category comprise all forces of nature, while the "additional hazard" category is assumed to comprise all initiating causes not suitable in any other class. The "additional hazards" are thereby the category coupled with most uncertainty.

In order to take critical plugs & stopped-flow into account, a seventh category called "Plugged/ Stopped-flow" was added. The "plugged/ stopped-flow" category failure fraction is not coupled to the other six categories, since most systems are design in a way so that high pressure does not lead to direct leakage. However, if subsea systems would not had such a design, pressure build up due to stopped flows would probably have been a main reason for leakage. Since the "Plugged/ Stopped-flow" category is additional, all failure fractions summarized are therefore exceeding 100 %. The damage categories are summarized into Table 12.

Protection layers are important tools in order to prevent or mitigate the consequences of an event. These protection layers are key factors when to determine the modified correction factor. The identified protection layers suitable for subsea systems are summarized in Table 13. The LOPA credit for each protection layer is presented with a recommended value, an interval, a SIL-requirement or the comment “Lack of data”. In the first two cases, the LOPA credits are in one way or another based on statistical data. In the third case, the protection layer is a SIF where no SIL level is yet determined. The ‘Lack of data’ comment means that there are not enough data available to present any recommended LOPA credit intervals. The LOPA expert group simply has to do a qualitative estimate based on their experience.

Table 14 and Table 15 are already filled in. In this case, it is made with respect to the hypothetical system showed in Figure 34.  Slightly modifications can be made in order to better suit the specific subsea system.

**Table 12 Show a summary of initiating cause categorization**

| Damage category | Initiating causes | |
|---|---|---|
| Corrosion | Internal corrosion<br>External corrosion | |
| External loads | Loads from trawls<br>Ship anchors<br>Sinking ships | Dropped objects<br>Collisions |
| Material | Weld defects<br>Steel defects | |
| Natural Hazards | Subsea landslide<br>Extreme weather<br>Vibrations | |
| Structural | Buckling<br>Hammer effect<br>Free spans | Joule-Thomson effect<br>Vortex induced vibrations |
| Additional hazard | Fire & Explosion<br>Sabotage | Erosion<br>Marine growth |
| Plugs / Stopped-flow | In case of no inherently pressure safe design | |

**Table 13 Summary of protection layers**

| PL # | Protection Layer | LOPA Credit | PL # | Protection Layer | LOPA Credit |
|---|---|---|---|---|---|
| 1 | Pressure Safe Design | 0.01 | 8 | Isolation of riser, SSIV | SIL1-SIL3 |
| 2 | Corrosion Protective Design | Lack of data | 9 | Isolation of subsea well | SIL1-SIL3 |
| 3 | Buried and/or trenched pipelines | 0.2-2.0 | 10 | BPCS Choke | 0.1-1.0 |
| 4 | Template | 1.0-10.0 | 11 | Erosion Sensors | Lack of data |
| 5 | High grade steel in pipelines | 0.1-1.0 | 12 | Abnormal Pressure Temperature Alarm | 1.0 – 10.0 |
| 6 | High Pressure Trip, HIPPS | 0.001-1 | 13 | Leakage detector | 0.4 – 1.0 |
| 7 | Low Pressure Trip, HIPPS | SIL1-SIL3 | 14 | Artificial Neural Network Warning | Lack of data |

As seen in Table 13, some PLs can have a credit nether higher or lower than 1. It refers to the fact that the LOPA credit in this thesis affects the generic frequency of a subsea leakage. Since several PLs are already incorporated in those systems in which the generic failure frequency are based upon, lack of such a PL results in a form of “design punishment”.

When subsea units specific failure frequency is estimated by multiplying the base failure frequency by modified correction factor ($M_{CF}$). All necessary failure frequencies can be calculated by the equations below:

(Equation 6) $F_{wellhead\ \&\ Xmas\ tree} = F_{B.Wellhead\ \&\ Xmas\ tree} \cdot M_{CF-W\&T}$

(Equation 7) $F_{Pipelines} = F_{B.Pipelines} \cdot M_{CF-P}$

(Equation 8) $F_{Manifold} = F_{B.Manifold} \cdot M_{CF-M}$

(Equation 9) $F_{Riser} = F_{B.Riser} \cdot M_{CF-R}$

(Equation 10) $F_{Subsea\ System} = F_{Riser} + F_{Manifold} + F_{Pipelines} + F_{wellhead\ \&\ Xmas\ tree}$

$F_{Subsea\ System}$ = Total release frequency for a specific subsea system
$M_{CF}$ = Modified correction factor for a subsea unit
$F_{B.}$ = System specific base failure frequency for different subsea units, determined in chapter 4.

The modified correction factor concerning pipelines in the safety zone has to be handled separately, since the conditions in the safety zone differ from the open sea. The correction factor is determined by qualitative judgement within the LOPA group.
Two things have to be taken into account when to do that judgement:

- The generic external load failure fraction is increased from 0.42 to 0.7 due to higher ship traffic density and increased probability of dropped objects, see Table 5.
- High graded steel gives extra protection within the safety zone. See section 6.4.3 for more information.

The specific failure frequency for pipelines in safety zone can then be calculated according to equation 11.

(Equation 11) $F_{P.SafetyZone} = F_{B.P.SafetyZone} \cdot M_{CF-P.SafetyZone}$

$M_{CF-P.SafetyZone}$ = Modified correction factor for pipelines in safety zone

**Table 14 Table for determination of the modified correction factor**

| Scenario | Initiating causes | Base Failure fraction[1] | Frequency Correction Factor (GoM examples)[2] | PL1 | PL2 | PL3 | PL4[3] | PL5 | PL6[45] | PL7[4] | PL8 | PL9 | PL10 | PL11 | PL12 | PL13 | Modified Correction Factor, $M_{CF}$ |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Damage of pipelines and flowlines | Corrosion | 0.40 | 0.8 – 2.0 (1.5) | | X | | | X | | X | | X | X | | X | X | |
| | External loads | 0.26 | 0.2 – 10 (0.3) | | | X | | X | | X | | X | X | | X | X | |
| | Material | 0.15 | 0.3 – 3.0 (0.4) | | | | | X | | X | | X | X | | X | X | |
| | Natural Hazards | 0.05 | 0.8 - 5.0 (3.4) | | | | | X | | X | | X | X | | X | X | |
| | Structural | 0.02 | 0.8 – 3.0 (1.6) | | | | | X | | X | | X | X | | X | X | |
| | Additional hazards | 0.12 | 0.8 – 3.0 (1.6) | | | | | X | | X | | X | X | X | X | X | |
| | Plugs / Stopped-flow | 0.5 | 1.0-3.0 | X | | | | | X | X | | X | X | | X | X | |
| Destruction of Well head and/or Xmas tree | Corrosion | 0.40 | 0.8 – 2.0 (1.5) | | X | | | | | | | X | | | X | X | |
| | External loads | 0.26 | 0.2 – 10 (0.3) | | | | X | | | | | X | | | X | X | |
| | Material | 0.15 | 0.3 – 3.0 (0.4) | | | | | | | | | X | | | X | X | |
| | Natural Hazards | 0.05 | 0.8 - 5.0 (3.4) | | | | | | | | | X | | | X | X | |
| | Structural | 0.02 | 0.8 – 3.0 (1.6) | | | | | | | | | X | | | X | X | |
| | Additional hazards | 0.12 | 0.8 – 3.0 (1.6) | | | | | | | | | X | | X | X | X | |

[1]Failure fraction statistic based on pipeline incidents leading to leakage in the North Sea /9/.
[2]Examples of correction factors for a GoM subsea system /9/.
[3]Absence of these protection layers may lead to an increased failure frequency
[4]The protection layer only protects the subsea system if the damaged area is situated downstream the protection layer, PL

**Table 15 Table for determination of the modified correction factor (* see footnotes below Table 14)**

| Scenario | Initiating causes | Base Failure fraction[1] | Frequency Correction Factor (GoM examples)[2] | PL1 | PL2 | PL3 | PL4[3] | PL5 | PL6[45] | PL7[4] | PL8 | PL9[4] | PL10 | PL11 | PL12 | PL13 | Modified Correction Factor, $M_{CF}$ |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Manifold collapse | Corrosion | 0.40 | 0.8 – 2.0 (1.5) | | X | | | | | | | X | X | | X | X | |
| | External loads[4] | 0.26 | 0.2 – 10 (0.3) | | | | X | | | | | X | X | | X | X | |
| | Material[5] | 0.15 | 0.3 – 3.0 (0.4) | | | | | | | | | X | X | | X | X | |
| | Natural Hazards[6] | 0.05 | 0.8 - 5.0 (3.4) | | | | | | | | | X | X | | X | X | |
| | Structural[7] | 0.02 | 0.8 – 3.0 (1.6) | | | | | | | | | X | X | | X | X | |
| | Additional hazards | 0.12 | 0.8 – 3.0 (1.6) | | | | | | | | | X | X | X | X | X | |
| | Plugs / Stopped-flow | 0.5 | 1.0-5.0 | X | | | | | X | | | X | X | | X | X | |
| Rupture of riser | Corrosion | 0.40 | 0.8 – 2.0 (1.5) | | X | | | | | X | X | X | X | | X | X | |
| | External loads | 0.26 | 0.2 – 10 (0.3) | | | | | | | X | X | X | X | | X | X | |
| | Material | 0.15 | 0.3 – 3.0 (0.4) | | | | | | | X | X | X | X | | X | X | |
| | Natural Hazards | 0.05 | 0.8 - 5.0 (3.4) | | | | | | | X | X | X | X | | X | X | |
| | Structural | 0.02 | 0.8 – 3.0 (1.6) | | | | | | | X | X | X | X | | X | X | |
| | Additional hazards | 0.12 | 0.8 – 3.0 (1.6) | | | | | | | X | X | X | X | X | X | X | |
| | Plugs / Stopped-flow | 0.5 | 1.0-5.0 | X | | | | | X | X | X | X | X | | X | X | |
| Topside blowout | | | 0.5-2.0 | | | | | | X | X | X | X | X | | X | | |

## 7.2 Consequence analysis

Since risk is defined as a combination of frequency and consequence, calculation of consequences are an important factor when to determine the total subsea system risk. In this LOPA-approach, the consequences are defined as environmental, commercial and safety impact. Environmental impact is assumed to be correlated with the oil spill amount, while safety impact depends on several factors affecting the number of personnel injuries or fatalities during an incident. The consequence analysis process is further described below.

### 7.2.1 Quantity of the oil release

The total oil spill amount can be calculated by multiplying the massflow and the oil release duration time, as shown in equation 12. Mass flow is a function of differential pressure, hole size, friction loss and duration time. Duration time on the other hand is estimated by the LOPA-group. Mean repair time, water depth, accessibility and system complexity may be factors to take into account when doing that estimate. All affecting factors are further described in this section.

(Equation 12) Oil Spill Amount [tonnes] = $\dot{m}_{oil} \cdot \mathbf{T}$

$\dot{m}_{oil}$ = mass flow [tonnes/hour]
**T** = Leakage duration time [hours]

*Hole size:* Table 16 shows the consequences in terms of hole sizes. The hole size is an important factor when calculating the total hydrocarbon release, in order to determine the severity of the consequence. The table is slightly modified from its original source, since subsea pipeline- and riser hole sizes has been divided into five hole size classes, in order to better suit the risk acceptance criteria which are also divided into five consequence classes. Furthermore, average hole sizes for pipelines and risers have been calculated based on an 8" tube. The average hole sizes are useful when to estimate the average yearly oil spill amount. All holes are assumed to be of circular shape.

**Table 16 Probabilities of different hole sizes and full ruptures /44/**

| Hole Size [Diameter] | Subsea Pipeline [%] | Riser [%] | Area [$m^2$] |
|---|---|---|---|
| Full rupture, 16" | - | 12 | $400 \cdot 10^{-4}\pi$ |
| Full rupture, 8" | 8 | - | $100 \cdot 10^{-4}\pi$ |
| Large 100mm | 2 | 13 | $25 \cdot 10^{-4}\pi$ |
| Significant 80 | 8 | 7 | $16 \cdot 10^{-4}\pi$ |
| Medium 50mm | 8 | 8 | $6{,}25 \cdot 10^{-4}\pi$ |
| Small 20mm | 74 | 60 | $1 \cdot 10^{-4}\pi$ |
| Average pipeline, 33mm | 100 | - | $11 \cdot 10^{-4}\pi$ |
| Average riser, 146mm | - | 100 | $53 \cdot 10^{-4}\pi$ |

*Duration time:* When estimating the consequences, the duration of the release is an important factor. In this thesis, the duration is assumed to be a function out of the maintenance time. However, it seems logical to argue that the maintenance time will vary depending on surrounding circumstances, difficult accessibility, available emergency response equipment etcetera. For example, in shallow water it is possible to use divers for maintenance and/or repair operations, but in deep and/or ultra-deep water only ROVs can be used, whereupon it may take longer time to repair a leak at ultra-deep water. A correction factor ($T_{CF}$) coupled to these specific circumstances should therefore be determined within the LOPA expert group. Table 17 provides an example of a correction factor based on water depth/accessibility. Note that the table is just an example and not based on any statistical source.

**Table 17 Maintenance correction factors due to depth**

| Water depth | [m] | Time Correction factor, $T_{CF}$ |
|---|---|---|
| Shallow water | <200 | 0.5 |
| Deep water | 200-1500 | 1 |
| Ultra-deep water | >1500 | 5 |

The total leakage duration time can be calculated by equation 13. Note that the duration time is the leakage time if all IPLs fail to stop the flow.

(Equation 13) $$\mathbf{T} = T \cdot T_{CF}$$

$\mathbf{T}$ = Leakage duration time [hours]
$T$ = Maintenance time, Table 4 & Table 5
$T_{CF}$ = Time Correction Factor, Table 17

*Mass flow:* Massflow is an important factor when to determine the consequences of an incident. Many factors affecting the severity of the consequences, but the release amount in tonnes is a simple and easily understandable concept. The massflow is a function of differential pressure between the pressure from the oil and the outside water pressure, the hole size and the density of the oil, see equation 14. The equation is based on Bernoulli equation. Approximate values can be taken directly from Table 19. The C value, *vena contra*, is a contraction coefficient varying in range 0.6-1.0, where the lower value shall be used if the hole has sharp edges /43/. Table 19 is based on a C value set to 0.8 and oil density 880kg/m$^3$.

(Equation 14) $$\dot{m}_{oil} = A_{hole} \cdot C \cdot \sqrt{\rho_{oil}} \cdot \sqrt{2\left(P_{oil} - P_{Water} - \Delta P_f\right)}$$
$$P_{Water} = \rho_{Water} \cdot g \cdot h$$

$\dot{m}_{oil}$ = Mass flow [kg/s]
$A_{hole}$ = Hole size [m$^2$]
$\rho_{oil}$ = Density of oil, (880 as an average value) [kg/m$^3$]
$P_{oil}$ = Full wellbore pressure [Pa]
$\rho_{oil} - P_{oil}$ = Differential pressure [Pa]
$P_{Water}$ = Water pressure due to depth [Pa]
$g$ = Gravity constant ≈ 10m/s$^2$
$h$ = Depth [m]
$C$ = 0.8 (0.6-1.0)
$\Delta P_f$ = Major pressure loss in pipelines

Especially if there are long pipelines with high flow velocity, there may be significant pressure drops along the pipeline length due to friction. In order to calculate the pressure drop, the velocity (V) and the Reynolds number (Re) needs to be calculated. Depending on whether the flow is considered as laminar or turbulent, Darcys friction factor (f) can be calculated by equation 17 or equation 18. Finally, the major pressure loss can be calculated by using equation 19. The overall calculation process is presented below, equation 15 to 19 /43/. If Table 19 is used, the calculated pressure losses have to be subtracted the initial differential pressure, e.g. $\Delta P = P_{oil} - P_{Water} - \Delta P_f$. The scenario specific oil spill size can be calculated by filling in Table 18.

(Equation 15) $$V = \frac{\dot{V}}{A}$$

(Equation 16) $$Re = \frac{\rho V d_h}{\mu}$$

(Equation 17) $$Re < 2100: \; f = \frac{64}{Re}$$

(Equation 18) Re > 4000: $$f = \left(1 \Big/ \left(-1.8 \lg\left(\left(\frac{\varepsilon/d_h}{3.7}\right)^{1.11} + \frac{6.9}{Re}\right)\right)\right)^2$$

(Equation 19) $$\Delta P_f = f \cdot \frac{L}{d_h} \cdot \frac{\rho V^2}{2}$$

| | |
|---|---|
| $V$ | = Flow rate [m/s] |
| $\dot{V}$ | = Volume flow [$m^3$/s] |
| $A$ | = Hole size [$m^2$] |
| $Re$ | = Reynolds number |
| $f$ | = Darcys friction factor |
| $\varepsilon$ | = Commercial iron pipes, 0.045 [mm] |
| $d_h$ | = Inside pipeline diameter [mm] |
| $L$ | = Pipeline length [m] |
| $\mu$ | = Dynamic viscosity, $\approx 90 \cdot 10^{-3}$ [Pa] |

**Table 18 to fill in for an estimate of the total oil spill amount**

| Equipment class | Hole size [$m^2$] | | [%] | Frequency[1] [$10^{-5}$] | $\dot{m}$[2] [Tonnes/h] | T[3] [Hours] | $m_{tot}$[4] [Tonnes] |
|---|---|---|---|---|---|---|---|
| Wellhead & Xmas tree | Full rupture | $100 \cdot 10^{-4}\pi$ | 8 | | | $T_{XMT} \cdot T_{CF}$ | |
| | Large | $25 \cdot 10^{-4}\pi$ | 2 | | | | |
| | Significant | $16 \cdot 10^{-4}\pi$ | 8 | | | | |
| | Medium | $6{,}25 \cdot 10^{-4}\pi$ | 8 | | | | |
| | Small | $1 \cdot 10^{-4}\pi$ | 74 | | | | |
| Manifold | Full rupture | $100 \cdot 10^{-4}$ | 8 | | | $T_{Manifold} \cdot T_{CF}$ | |
| | Large | $25 \cdot 10^{-4}\pi$ | 2 | | | | |
| | Significant | $16 \cdot 10^{-4}\pi$ | 8 | | | | |
| | Medium | $6{,}25 \cdot 10^{-4}\pi$ | 8 | | | | |
| | Small | $1 \cdot 10^{-4}\pi$ | 74 | | | | |
| Pipelines | Full rupture | $100 \cdot 10^{-4}$ | 8 | | | $T_{Pipelines} \cdot T_{CF}$ | |
| | Large | $25 \cdot 10^{-4}\pi$ | 2 | | | | |
| | Significant | $16 \cdot 10^{-4}\pi$ | 8 | | | | |
| | Medium | $6{,}25 \cdot 10^{-4}\pi$ | 8 | | | | |
| | Small | $1 \cdot 10^{-4}\pi$ | 74 | | | | |
| Riser | Full rupture | $100 \cdot 10^{-4}$ | 12 | | | $T_{Riser} \cdot T_{CF}$ | |
| | Large | $25 \cdot 10^{-4}\pi$ | 13 | | | | |
| | Significant | $16 \cdot 10^{-4}\pi$ | 7 | | | | |
| | Medium | $6{,}25 \cdot 10^{-4}\pi$ | 8 | | | | |
| | Small | $1 \cdot 10^{-4}\pi$ | 60 | | | | |

[1] Determined by methods presented in 4.2.
[2] Determined by equation 14 or Table 19
[3] Determined by equation 13
[4] Determinded by equation 12.
[5] Hole size and hole size fraction according to Table 16

**Table 19 Approximate hydrocarbon mass flow due to differential pressure and hole size.**[1]

| | Massflow, $\dot{m}$ [tonnes/h] | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| $\Delta P$[3] [Bar] | Small | Medium | Significant | Large | Rupture 8” | Rupture 16” | Average[4] Pipeline, 8” | Average [2 4] Riser16” |
| 1 | 3 | 21 | 53 | 83 | 333 | 1333 | 37 | 177 |
| 2 | 5 | 29 | 75 | 118 | 471 | 1885 | 52 | 250 |
| 5 | 7 | 47 | 119 | 186 | 745 | 2981 | 82 | 395 |
| 10 | 11 | 66 | 169 | 263 | 1054 | 4215 | 116 | 559 |
| 15 | 13 | 81 | 207 | 323 | 1291 | 5163 | 142 | 684 |
| 20 | 15 | 93 | 238 | 373 | 1490 | 5961 | 164 | 790 |
| 25 | 17 | 104 | 267 | 417 | 1666 | 6665 | 183 | 883 |
| 30 | 18 | 114 | 292 | 456 | 1825 | 7301 | 201 | 967 |
| 35 | 20 | 123 | 315 | 493 | 1972 | 7886 | 217 | 1045 |
| 40 | 21 | 132 | 337 | 527 | 2108 | 8431 | 232 | 1117 |
| 45 | 22 | 140 | 358 | 559 | 2236 | 8942 | 246 | 1185 |
| 50 | 24 | 147 | 377 | 589 | 2356 | 9426 | 259 | 1249 |
| 55 | 25 | 154 | 395 | 618 | 2471 | 9886 | 272 | 1310 |
| 60 | 26 | 161 | 413 | 645 | 2581 | 10326 | 284 | 1368 |
| 65 | 27 | 168 | 430 | 672 | 2687 | 10747 | 296 | 1424 |
| 70 | 28 | 174 | 446 | 697 | 2788 | 11153 | 307 | 1478 |
| 75 | 29 | 180 | 462 | 722 | 2886 | 11544 | 317 | 1530 |
| 80 | 30 | 186 | 477 | 745 | 2981 | 11923 | 328 | 1580 |
| 85 | 31 | 192 | 492 | 768 | 3072 | 12290 | 338 | 1628 |
| 90 | 32 | 198 | 506 | 790 | 3162 | 12646 | 348 | 1676 |
| 95 | 32 | 203 | 520 | 812 | 3248 | 12993 | 357 | 1722 |
| 100 | 33 | 208 | 533 | 833 | 3333 | 13330 | 367 | 1766 |
| 105 | 34 | 213 | 546 | 854 | 3415 | 13659 | 376 | 1810 |
| 110 | 35 | 218 | 559 | 874 | 3495 | 13981 | 384 | 1852 |
| 115 | 36 | 223 | 572 | 893 | 3574 | 14295 | 393 | 1894 |
| 120 | 37 | 228 | 584 | 913 | 3651 | 14602 | 402 | 1935 |
| 125 | 37 | 233 | 596 | 931 | 3726 | 14904 | 410 | 1975 |
| 130 | 38 | 237 | 608 | 950 | 3800 | 15199 | 418 | 2014 |
| 135 | 39 | 242 | 620 | 968 | 3872 | 15488 | 426 | 2052 |
| 140 | 39 | 246 | 631 | 986 | 3943 | 15772 | 434 | 2090 |
| 145 | 40 | 251 | 642 | 1003 | 4013 | 16052 | 441 | 2127 |
| 150 | 41 | 255 | 653 | 1020 | 4082 | 16326 | 449 | 2163 |
| 155 | 41 | 259 | 664 | 1037 | 4149 | 16596 | 456 | 2199 |
| 160 | 42 | 263 | 674 | 1054 | 4215 | 16861 | 464 | 2234 |
| 165 | 43 | 268 | 685 | 1070 | 4281 | 17123 | 471 | 2269 |
| 170 | 43 | 272 | 695 | 1086 | 4345 | 17380 | 478 | 2303 |
| 175 | 44 | 276 | 705 | 1102 | 4409 | 17634 | 485 | 2337 |
| 180 | 45 | 279 | 715 | 1118 | 4471 | 17884 | 492 | 2370 |
| 185 | 45 | 283 | 725 | 1133 | 4533 | 18131 | 499 | 2402 |
| 190 | 46 | 287 | 735 | 1148 | 4594 | 18374 | 505 | 2435 |
| 195 | 47 | 291 | 745 | 1163 | 4654 | 18615 | 512 | 2466 |
| 200 | 47 | 295 | 754 | 1178 | 4713 | 18852 | 518 | 2498 |

[1] Hole size diameter according to Table 16
[2] If Only one pipeline is linked to the riser, a riser rupture massflow cannot exceed the pipeline massflow due to mass balance.
[3] The wellbore pressure minus the pressure from the water and the friction losses, e.g. $\Delta P = P_{oil} - P_{Water} - \Delta P_f$
[4] The average hole size when hole size fraction and full rupture is taken into account

### 7.2.2 Scenario specific safety risk

The safety risk depends on several factors. For example, the safety impact frequency depends on the system design and the topside blowout frequency. Secondly, the consequence severity depends on the number of immediate fatalities and the number of escape, evacuation and rescue related fatalities. In the first case, mitigating protection layers has no effect at all, but well in the second case.

It has been observed that platforms roughly designed at the same time can differ very much in a risk perspective. So far, there are no statistical data available to make clear distinctions between different kinds of installations /58/. Therefore, several assumptions have to be made when to estimate the scenario specific risk. Table 20 can be used as support when doing these assumptions. However, the LOPA group shall feel free to discuss other safety related aspects as well.

**Table 20 Affecting factor to consider when determine the adjustment factors**

| | Affecting factor | Comments |
|---|---|---|
| A | Number of people on the platform | More people on the platform increases the probability of fatalities. |
| B | Personnel in dangerous zone | A higher concentration of personnel in the affected zone may cause an increased number of fatalities. For instance, people who are indoors would most likely not be as affected by immediate effects of a leakage as operators outdoor. |
| C | Alarms | Leak detection systems and fire & gas detection system can warn the platform personnel, so that they can perform proper actions in time. Both the platform personnel emergency response education level and the detector reliability, compared to petroleum industry North Sea average, can be discussed within the LOPA group. |
| D | Ignition probability | Ignition of hydrocarbons is a major threat. Both gas cloud explosions and surface fires can lead to immediate fatalities, escalation to topside units and degradation of the structure. If the ignition occurs shortly after a leak has occurred, people may not have time to escape.<br><br>In this thesis, a base ignition probability is set to 0.008 for liquid hydrocarbon releases and 0.03 for gas releases. It is a tenth of the recommended ignition probabilities for topside releases used by a large oil producer active in the North Sea region. The lower probability is motivated since the release is most likely to occur far away from the topside ignition sources. |
| E | Mitigating and preventive protection layers | Mitigating and preventive protection layers are important tools in order to control or prevent a hazardous situation. In this case, the LOPA group have to consider whether there are an increased or decreased probability of a blowout, compared with the North Sea average.<br><br>The base topside blowout frequency for production wells in the North Sea is set to $9.8 \cdot 10^{-6}$ per well $\cdot$ year. It is a conservative estimate, since the original source also takes marine blowouts into account. Note that the generic frequency is an incident rate, i.e. when all preventive protection layers have already failed. |
| F | Evacuation | Evacuation includes all personnel leaving their working stations when and heading against the muster station, which are usually |

| | | |
|---|---|---|
| | | lifeboats. Success in escape include several factors such as /58/:<br>- Size of the accident<br>- Duration time<br>- Heat load and smoke<br>- Heat and smoke protection<br>- Wind speed and wind direction<br>- Capacity of escape ways and stairs<br>- Alternative routes |
| G | Free fall life boats | Statistic shows that presence of free fall lifeboats have a considerable effect on the risk level. For example, if studying Norwegian early 1990s steel jacket platforms, those equipped with free fall life boats had reduced their fatal accident rate by almost 50 % /58/. |

*Determine risk*: Safety risk is a combination of how often a hazardous event occurs and what its consequences are. The frequency of a hazardous event depends on:

- Specific pipeline leakage frequency in the safety zone
- Specific riser leakage
- Specific topside blowout frequency

The two first bullet points are determined according to the method presented in section 7.1. The specific topside blowout frequency on the other hand has to be determined by qualitative judgement of the LOPA expert group. Therefore, the adjustment factor $A_2$ is introduced.
The specific topside blowout frequency can be decided by using equation 20.

(Equation 20) $F_{T.Blowout\ specific} = F_{B.T\text{-}blowout} \cdot A_2$

$A_2$: Topside blowout adjustment factor (See Table 20, E)
$F_{B.T\text{-}blowout}$: Base failure frequency per well · year, $9.8 \cdot 10^{-6}$/year

The next step is to determine the severity of the consequences. The consequences are divided into five severity classes which correspond to the TMEL, see Table 6. The LOPA group have to determine the hazard distribution, e.g. how often the consequences reaches more than ten fatalities, 1-10 fatalities, 1 fatality, 1 permanent injury and one injury. The following facts, as well as Table 20, can be used as a guide when to estimate the hazard distribution. Keep in mind that these statements below are based on topside accidents and may not be 100 % correct if transferred direct into subsea system context.

- The probability of fatalities and injuries can be considered as more or less equal;
- The fraction of fatal accidents is higher in the US GoM than in the North Sea;
- For minor explosions, it seems that 15 % of all accidents result in fatalities;
- For stronger explosions, 33 % of all cases leads to 10 fatalities or more;
- Of all topside fires, 10 % leads to an average number of 1.7 fatalities /58/.

Finally, the risk can be calculated by using equation 21. In that formula, the LOPA group also has to estimate the ignition probability. Table 20 (section D) can be used as support for that judgement.

(Equation 21) Safety risk = $(F_{T.Blowout\ specific} + F_{P.SafetyZone} + F_{riser}) \cdot A_1 \cdot D$

$A_1$ = Ignition probability (See Table 20, D)
Safety risk = The frequency of an event leading to a specific consequence
D = Consequence distribution, e.g. $D_{(1\text{-}10\ fatalities)}$

## 7.3 SIL determination

When to determine appropriate SILs, environmental, commercial and safety impacts are taken into consideration. The needed risk reduction (RR) can be calculated by dividing the frequency of a specific event by the acceptable frequency. For example, the needed RR for a release of major release of 10 000 tonnes of crude oil can be estimated by dividing the hazardous event frequency by the ERAC value, as shown in equation 22. On the other hand, if the consequence is safety related or include commercial impact, the event frequency should be divided by TMEL or CRAC instead, as shown in equation 23 and equation 24. A RR-value below 1 is considered as acceptable while a RR-value exceeding 1 indicates a need of additional safety measures. Detailed information about TMEL, ERAC and CRAC can be found in chapter 5.

The total risk can be reduced by adding IPLs. The IPL SIFs have a SIL value varying in range SIL1 to SIL3. In this thesis, three IPLs that may be considered with regards to SIL requirements have been identified, as shown in Table 21. Only the IPL mitigating functions are considered, since the preventive functions is already included in the specific system base failure frequency.

**Table 21 Show different subsea IPLs and SIL risk reduction facors**

| IPL | Subsea unit | Function |
|---|---|---|
| SIL(X) | Wellhead & Xmas tree | Isolation of subsea well |
| SIL(Y) | Pipeline | HIPPS (Preventive function) |
| SIL(Z) | Riser | Subsea isolation valve (SSIV) |
| SIL | Subsea unit | Risk Reduction factor |
| SIL 1 | 0.1-0.01 | 0.1-0.01 |
| SIL 2 | 0.01-0.001 | 0.01-0.001 |
| SIL 3 | 0.001-0.0001 | 0.001-0.0001 |

When determining the necessary SIL requirement for a SIF, it is crucial to know which part of the system it actually protects. For example, imagine a pipeline rupture causing a massive oil release. In such a case, isolation of the subsea well would stop the hydrocarbon flow and mitigate the consequences. However, closing the subsea isolation valve (SSIV), located on the riser installation, would have no effect at all. The SSIV only protects the riser installation, which is just a small part of the subsea system. Therefore, according to the reasoning above, the SIFs have to be weighted due to its location, as shown in equation 22. As seen in the equation, the well isolation SIF risk reduction factor is multiplied by the overall system failure frequency, e.g. all subsea unit frequencies. The subsea isolation valve risk reduction factor on the other hand is only multiplied by the riser failure frequency. Consequently it only protects the riser installation which is just a small part of the overall system. It is therefore logical that the usage of this model often end up with SIL3 or SIL2 requirements for the “isolation of well function”, see Appendix A – Validation of the model. That SIF simply protects the system the most. Such a result also corresponds to recommendations in national guidelines, such as OLF 070.

A schematic picture of how protection layers can be located is shown in Appendix B, Figure 34. If the system differs a great deal from the schematic picture, the equation may have to be slightly modified.

*Environmental impact:*
The ERAC is coupled to the oil spill amount, and is found in **Table 7**. However, other factors such as distance to shore, presence of vulnerable resources and water temperature are also affecting the outcome. Therefore, an environmental damage correction factor ($CF_{ERAC}$) is introduced. The field specific $CF_{ERAC}$ is determined according to the instruction in section 5.2.

(Equation 22) $$RR = \frac{SIL(X)\left(F_{Wellad\ \&\ Xmas\ tree} + F_{Manifold} + SIL(Y)\left(F_{Pipelines} + (SIL(Z)\cdot F_{Riser})\right)\right)}{ERAC \cdot CF_{ERAC}}$$

| | |
|---|---|
| $F_{manifold}$ | = Total release frequency for a specific manifold |
| $F_{pipelines}$ | = Total release frequency for a specific pipeline system |
| $F_{riser}$ | = Total release frequency for a specific riser installation |
| $F_{Wellhead\ \&\ Xmas\ tree}$ | = Total release frequency for a specific wellhead & Xmas tree |
| SIL(X) | = SIL determination on IPL X, e.g. shutting in well SIF. |
| SIL(Y) | = SIL determination on IPL Y, e.g. subsea HIPPS. |
| SIL(Z) | = SIL determination on IPL Z, e.g. SSIV. |
| ERAC | = Environmental Risk Acceptance Criteria, Table 6 |
| $CF_{ERAC}$ | = Need of extra safety requirements, section 5.2 (0-3 'yes'), |

*Commercial impact:*
Just as in the environmental impact scenario, the SIF location has to be taken into account when estimating the total commercial risk. A SIF closer to the hydrocarbon source is considered as more protective than a SIF near the subsea system boundary. Appendix A, Figure 34, show a schematic picture of how SIFs can be located on a subsea system. Since both commercial and environmental impact are coupled to the oil spill amount, these two equation looks very similar.

The big difference is the risk acceptance criteria, CRAC. CRAC depends on the region where the accident occur and the oil spill amount. The CRAC can be found in
Table 9.

(Equation 23) $$RR = \frac{SIL(X)\left(F_{Wellad\ \&\ Xmas\ tree} + F_{Manifold} + SIL(Y)\left(F_{Pipelines} + (SIL(Z)\cdot F_{Riser})\right)\right)}{CRAC}$$

| | |
|---|---|
| $F_{manifold}$ | = Total release frequency for a specific manifold |
| $F_{pipelines}$ | = Total release frequency for a specific pipeline system |
| $F_{riser}$ | = Total release frequency for a specific riser installation |
| $F_{Wellhead\ \&\ Xmas\ tree}$ | = Total release frequency for a specific wellhead & Xmas tree |
| SIL(X) | = SIL determination on IPL X, e.g. shutting in well SIF. |
| SIL(Y) | = SIL determination on IPL Y, e.g. HIPPS function. |
| SIL(Z) | = SIL determination on IPL Z, e.g. SSIV. |
| CRAC | = Commercial Risk Acceptance Criteria [ Table 9] |

*Safety impact:*
In safety related cases, people may die directly or in evacuation and/or response phase. Mitigating protection layers will not have any protective effect in the first situation. If a person is lost due to an explosion, the life will not be saved by mitigate the fire and/or stop the hydrocarbon flow. However, mitigating action will increase safety during evacuation and response phase. Therefore, the term Θ which refers to the fraction of immediate fatalities is introduced is introduced. For example, if 50 % of all casualties would occur as an immediate consequence of the event, Θ is set to 0.5. In such a case, high reliability mitigating protection layers would only be able to decrease the total risk by about 50 %. Note that the preventive protection layers are also included in the overall risk estimate, since the event per year frequency has been modified by the modifying base frequency procedure, see section 7.1.

The TMEL value is chosen according to the consequence estimate and the event per year estimate. For example, if the consequence is assumed to be 1-10 fatalities per event, the TMEL would be $10^{-5}$/year according to Table 6.

(Equation 24) $RR = \frac{SIL(X) \cdot SIL(Y) \cdot SIL(Z) \cdot (1-\Theta) \cdot \text{safety risk} + \Theta \cdot \text{safety risk}}{TMEL}$

Safety risk = The frequency of an event leading to a specific consequence
TMEL = Target Mitigated Event Likelihood, Table 7
$\Theta$ = Fraction of immediate casualties

# 8. Discussion and Conclusion

Depletion of onshore and shallow water reserves, in combination with new subsea technology, has made the petroleum industry advance into deeper water in an increasing pace. However, new technology also brings new risks. These risks can be handled by the use of protection layers. The aim of this master thesis was to develop a method for applying LOPA in subsea context, in order to determine appropriate SIL for SIFs. When validating the model, it seems like this aim has been met. This discussion is divided into three parts, where the first part discusses the main LOPA-model, the second part discusses the complementary CBA-method and the last part comprises the overall conclusions.

## 8.1 The LOPA-model

When studying the LOPA validation result, it appears that the model provides credible output due to what is economically and technically feasible. For example, when evaluating a simple subsea satellite well system, such as the one described in Appendix A, the “Isolation of well” SIF ends up with SIL 3 requirements.  Other SIFs ends up in the lower range of SIL1. In this case, it is reasonable to believe that SIL 3 requirement for the “isolation of subsea well” SIF is appropriate, since it acts close to the hydrocarbon source and is the most effective way of lowering the overall system risk. The SIL3 requirement also corresponds well with the SIL recommendation provided in the Norwegian national guideline OLF 070.

During the validation process, environmental impact was found to cause more severe consequences than commercial- and safety impact. Therefore, ERAC became the design criteria. However, that does not always have to be the case. In another subsea context, the consequences out of commercial impact could be worse, and therefore considered as design criteria. Safety consequences on the other hand always seem to be smaller compared with environmental and commercial consequences. That seem logical, since the largest part of the subsea production systems are located outside the safety zone.

The model is semi-quantitative in its nature, which means that the output depends on a combination of generic statistical data, logical reasoning and engineering judgement. Therefore, the results shall not be considered as a self-evident truth but rather as a form of intelligent guessing. However, the needs of qualitative elements shall not be seen as a failure but more as a necessity, since there are no statistical data for all parameters affecting risk. Use of only generic data would not reflect reality in a good way, since there can be huge differences between subsea systems. No existing system is completely generic in design and surroundings.

As opposed to a standard LOPA, this LOPA-approach takes basis in a generic leak frequency instead of several initiating cause frequencies. This approach gives an advantage in subsea context, since there is lack of data concerning initial cause frequencies. By modifying the generic leakage frequency due to surrounding circumstances and subsea system properties, a credible subsea system risk can be estimated. Furthermore, the approach gives the advantage of taking the whole risk picture into account. Even unusual incidents are included into the generic failure frequency. On the other hand, this approach also has disadvantages since it is hard to know how a completely generic system looks like and which protection layers which are included in the generic data. That uncertainty makes it hard to estimate preventive barriers LOPA-credit. For example, which LOPA-credit shall be given a preventive function of a subsea HIPPS? If full credit is given, the preventive function would probably be overestimated. On the other hand, if the preventive part of the HIPPS is given no credit at all, it would be a too conservative since a subsea HIPPS certainly protects the system.

Even though the LOPA-model provides credible output, there are model uncertainties in which the user should be aware of. Some of these uncertainties are listed and discussed below:

- *Initiating causes and failure frequency:* The identified initiated causes are based on generic data and engineering judgement. It is possible that some failure mechanism, acting on a specific subsea system, may not have been identified. Furthermore, all failure mechanisms have been merged into seven failure categories, for which the generic failure fraction is known. However, the failure mechanism distribution within each failure category is still unknown. The event frequency correction factor ($M_{CF}$) is therefore coupled with a high degree of qualitative judgement.

- *LOPA credit*: Even though the recommended LOPA credit intervals are based on statistics, there are uncertainties with these estimates. In some cases, the available data of protection layers effectiveness has been limited. Regarding human IPLs, human response is often considered as the weakest link in the event-chain. However, the human error potential is hard to estimate qualitatively. In order to reduce that uncertainty, a human response reliability analysis can be used. However, it is considered beyond the scope of this master thesis.

- *Quantity of a hydrocarbon release:* The oil spill depends on a combination of differential pressure, hole size diameter and oil spill duration time. First of all, the duration time is based on the modified mean maintenance time and the qualitative estimate of the LOPA group. Secondly, the hole size distribution is divided into five main categories instead of 3-4 as in the original source. Finally, the calculation process itself involves uncertainties. However, the author of this report does not believe that a more advanced and time consuming calculation method would be worth the effort, since it would just marginally reduce the overall model uncertainty.

- *Safety impact:* The safety risk is affected by the consequence distribution and the ignition probability. Even though these assumptions are made according to a framework of logical reasoning, they still comply with the overall model uncertainty.

- *Risk Acceptance Criteria:* The risk acceptance criteria are limited to comprise environmental, commercial and safety risk. In all three cases, a linear relationship between consequence and frequency is assumed. In reality that may not be entirely true, since peoples risk perception is affected by multiple factors. However, a linear correlation has the advantage of being user friendly and easy to understand. In an already complex model, it is considered beneficial to keep these criteria as simple as possible.

- *ERAC* is coupled to the quantity and the frequency of a hydrocarbon release. The ERAC can also be adjusted by three correction factors, distance to shore, presence of valuable resources and water temperature. How much each factor affects the consequence is based on completely qualitative judgement. One way to improve the model is therefore to base these judgements on more data. However, even though these correction factors are coupled with uncertainty, it seems logical to increase the SIL requirements due to environmental sensitivity.
- *CRAC* is linked to the amount of oil spilled and an acceptable frequency of such a release. However, since the cost per-tonne estimate is based on releases from oil tankers, it may have been information loss when transferring these values into subsea context. Furthermore, CRAC is limited to comprise clean-up cost and compensation of damage. It can be argued that losses in stock-market and/or bad reputation would also be included. The author believes that including these factors could be a good way to improve the model in future work.

## 8.2 The CBA-model

This thesis also comprises a CBA method, which can be used to determine the most cost effective balance between safety requirements and oil & gas production. The consequences are measured in monetary terms, which enable to summarize various kinds of damage into a single cost.

However, the model is coupled with uncertainties. What is probably the biggest uncertainty is how to put a value of something not priced on the free market. For example, what is the value of a statistical human life, the value of 10 000 dead seabirds or the value of a non-oiled coast line? Some people would say that these assets are worth endless of money and cannot be priced, but that is not a realistic attitude when to handle risk. If that was the case, we would not be able to drive cars or go outside the house, since it always includes a small probability of dying. However, it shall also be stated that there are only statistical lives, and statistic environmental harm, which is valued. They do not exist in real life and shall just be seen as a tool for evaluating the benefits out of specific safety measures. Ten workers stuck on a burning platform are not considered statistical lives since they exist in real life and of course the emergency response personal should put efforts in rescuing them no matter of the cost.

Another uncertainty is coupled with benefit transfer. A total of five models are presented. All of them are based on assumptions and field specific surrounding conditions, such as nature, culture, currency, time, inflation, purchasing power etcetera. Transferring these results into another context automatically refers to loss of information. On the other hand, since it is not possible to develop new methods for every situation, benefit transfer seems to be the best option. Using calculation models and transferring the results into a similar context is a much better approach than just using qualitative judgement.

Even though this approach has its benefits, the model is only recommended to be used as a complementary model. The result can be used to motivate an increased SIL, but it is not recommended to be used for lowering safety requirements. The reason is that the model seems to "discriminate" high rated SIL-functions. For example, if a subsea system without any SIFs is assumed to cost 500 million NOK per year as an average, a SIL 1 (0.01) rated function would "save" 495 million NOK. That is a great amount of money, and the SIF would probably be implemented. A SIL 2 (0.001) rated function on the other hand would just save 4.5 million NOK more, and a SIL3 (0.0001) rated function would only save 0.45 million NOK. Several parallel SIL rated functions would be completely indefensible with this approach. The result should therefore be interpreted with caution.

## 8.3 Conclusion

The overall conclusion of this discussion is that the developed model provides a time effective way to estimate the necessary SIF SIL-requirements. The model is especially usable when the subsea system is too complex for using only qualitative judgement. The model provides creditable output and provides a way of evaluating the overall system. However, the model may be too simple if valuating very complex system. If that is the case, the user is recommended to modify the SIL-determination equations in order to better suit the specific case. It is not hard to modify the equation if the background is well understood, which can be considered as a great potential with this LOPA-approach. Furthermore, the model may also be extended to also comprise subsea well intervention or subsea production processing equipment.

The CBA can be used to determine the most cost effective balance between safety requirements and oil & gas production. However, the model is only recommended as a complementary model and the result should be interpreted with caution.

## 9. References


1. Alex W. Dawotola, P. H. A. J. M. van Gelder & J. K. Vrijling. (2011). *Decision Analysis Framework for Risk Management of Crude Oil Pipeline System.* The Netherlands: Hydraulic Engineering Section, Delft University of Technology.

2. Atkinson, S.M., Mourato, S., Pearce, D. (2006). *Cost-Benefit Analysis and the Environment.* Paris France: OECD, Organisation for Economic Cooperation and Development.

3. Bai, Y.,& Bai, Q. (2010). *Subsea Engineering Handbook.* Huston, U.S.A: Elsevier Inc.

4. Biervliet, K.V., Dirk, L.R., Paulo, A.L.D. (2006). *An Accidental Oil Spill Along the Belgian Coast: Result from a CV Study*. Department of Economics, University of Venice and Fondazione Eni Enrico Mattei

5. Carson, Richard T et al. (2003). Contingent Valuation and Lost Passive Use: Damages from the Exxon Valdez Oil Spill. *Environmental and Resource Economics*, 25: 257-286.

6. CPS. (2001). *Layer of Protection Analysis – Simplified Process Risk Assessment*. New York: Center for Chemical Process Safety of the American Institute of Chemical Engineers.

7. Cohen, Mark A. Muehlenbachs, L, Gerarden, T. (2011). *Discussion paper - Preliminary Empirical Assessment of Offshore Production Platforms in the Gulf of Mexico*. Washington DC: Resources for the Future.

8. Devold, H. (2006). *Oil and gas production handbook: An introduction to oil and gas production.* Oslo: ABB ATPA Oil and Gas.

9. DNV. (2009). *Integrity management of submarine pipeline systems.* Det Norske Veritas, Technical Note, DNV-RP-F116.

10. DNV. (2010). *Selection and use of subsea leak detection systems.* Det Norske Veritas, Technical Note. DVV-RP-F302.

11. EIA (U.S Energy Information Administration). [Web page].Available at: http://www.eia.gov/todayinenergy/detail.cfm?id=9530#
    Accessed: July, 2013

12. Enander, A. (2005). *Människors förhållningssätt till risker, olyckor och kriser*. Huskvarna: Ann Enander och Räddningsverket.

13. Encana. *Typical Well Casing Diagram*. [Web page]. Available at: http://www.encana.com/images/environment/well-casing.gif
    Accessed: July, 2013

14. Endresen, O., Skjong, R., & Vanem, E. (2006). *Cost-effectiveness criteria for marine oil spill preventive measures*. Hovik, Norway: DNV Research & Innovation.

15. Etkin, D. (2004). *Modeling oil spill response and damage costs*. NY: Environmental Research Consulting.

16. Etkin, S.D. (2000). *Worldwide Analysis of Marine Oil spill Cleanup Cost Factors.* Massachusettsm U.S.A: Environmental Research Consultning Winchester.

17. Francis, P.E. *Cathodic Protection*. [Web page]. Available at: http://www.google.se/url?sa=t&rct=j&q=&esrc=s&frm=1&source=web&cd=3&ved=0CEQQFjAC&url=http%3A%2F%2Fwww.npl.co.uk%2Fupload%2Fpdf%2Fcathodic_protection_in_practise.pdf&ei=FuwmUv6JEYORtQaTkYGgCg&usg=AFQjCNFSsPGo2u03-S05LXS9Ucidp7_EEg
Accessed: September, 2013

18. Franzig, H., Haeffler, L., Ljundman, Bo. (2003). *Handbok för riskanalys.* Räddningsverket.

19. Fredholm, O. (2001). *Tekniska riskanalysmetoder – En vägledning för identifiering, värdering och begränsning av risker vid industriell kemikaliehantering*. Stockholm: Kemikontoret.

20. Frost, A., Shahriari, M. (2007). *Oil Spill cleanup cost estimation – Developing a mathematical model for marine environment*. Gopthenburg Sweden: Department of production and Production Development, Chalmers University of Technology.

21. GE Inspection Technologies. *Corrosion & Erosion Inspection solutions for detection, sizing & monitoring*. [Web page]. Available at: http://www.google.se/url?sa=t&rct=j&q=&esrc=s&frm=1&source=web&cd=2&ved=0CDkQFjAB&url=http%3A%2F%2Fwww.gemcs.com%2Fdownload%2Fultrasound%2Fcorrosion-monitoring%2FGEIT-10017EN_corrosion-erosion-brochure-page.pdf&ei=0R8nUv2LDcPfswbznIHQAw&usg=AFQjCNGiqroa38Ko6m8kugMLsrF0WjYzhA . Accessed: September, 2013

22. Hasselström, L et al. (2012). *The value of ecosystem services at risk from oil spills in the Barents Sea.* Artic Games: Mistra Artic Futures in a Global Context

23. *How stuff works.* [Web page]. Available at: http://science.howstuffworks.com/environmental/energy/oil-refining1.htm
Accessed: July, 2013

24. HSE. (2001). *Reducing risks protecting people - HSE's decision-making process.* Health and Safety Executive.

25. HSE. (2006).*Safety zones around oil and gas installations in waters around the UK.* Health and Safety Executive.

26. IChemE. (2011). *Using risk graphs for Safety Integrity Level assessment – A user-guide for chemical engineers*. UK: Institution of Chemical Engineers, 1st edition.

27. IEC. (2003). *International Standard 61511, Functional safety – Safety instrumented systems for the process industry sector*. Geneva: International Electrotechnical Commission, First edition Part 1-3.

28. IEC. (2010). *International Standard 61508, Functional safety of electrical/electronic/programmable electronic safety-related systems* – Second edition *Part1-7.* Brussels: European Committee for Electrotechnical Standardization.

29. IMO. (2004). *Formal Safety Assessment risk Evaluation.* International Maritime Organization, MSC 78/19/2.

30. ISO10418.(2003). *Petroleum and natural gas industries - Offshore production installations - Basic surface process safety systems.*Brussels: European Commitee for Standardization.

31. Indian institute of technology, Madras. Department of Ocean Engineering. *Subsea production systems*. [Web page]. Available at:
http://www.youtube.com/watch?v=QBrrOw1eiGo
Accessed: June, 2013

*32.* ITOPF. (2003). *Oil Spill Risks and the State of Preparedness in the Regional Seas.* The International Tanker Owners Pollution Federation Limited.

33. ITOPF (The International Tanker Owners Pollution Federation Limited). *Case Histories – E.* [Web page]. Available at:
http://www.itopf.com/information-services/data-and-statistic/case-histories/elist.html#EXXON
Accessed: July, 2013

34. Jernelöv, A. (2010). *The Threats from Oil Spills: Now, Then, and in the Future*. Royal Swedish Academy of Sciences

35. Kannen, A., Kraft, D.,Liu, X., Wirtz,K.W. (2009). Willingness to pay among households to prevent coastal resources from polluting by oil spills. *Marine Pollution Bullentin,* 58: 1514-1521.

36. Karlsson, H. T. (2012). *Processriskanalys.* Lund Sweden: Department of Chemistry, Lunds Technical University.

37. Liu, X., Wirtz, K.W. (2009) The economy of oil spills: Direct and indirect costs as a function of spill size. *Journal of Hazardous Materials*, 171: 471-477.

38. Loureiro, M.L., Loomis, J-B.,& Vázquez M.T. (2009). Economic Valuation of Environmental Damages due to the Prestige Oil Spill in Spain, *Environ Resource Econ*, 44: 537-553.

39. Maersk Drilling. *Semi-submersibles.* [Web page]. Available at:
http://www.maerskdrilling.com/drillingrigs/semi-submersibles/pages/semi-submersibles.aspx
Accessed: July, 2013

40. Mattson, B. (2000). *Riskhantering vid skydd mot olyckor – problemlösning och beslutsfattande.* Karlstad: Räddningsverket.

41. McKie, R. *Gulf oil spill at Deepwater Horizon threatens $8bn clean-up and an ecological oil slick disaster for the US*. [Web page]. The Guardian. Available at:
http://www.theguardian.com/environment/2010/may/02/bp-oil-spill-costs-impact
Accessed: August, 2013

42. Naturvårdsverket. *Miljövärdering*. [Web page]. Available at: http://www.naturvardsverket.se/Miljoarbete-i-samhallet/Miljoarbete-i-Sverige/Uppdelat-efter-omrade/Miljoekonomi/Miljovardering/
Accessed: July, 2013

43. Norberg, C. (2010). *Kompendium I grundläggande strömningslära*. Lund Sweden: Department of Energy Sciences, Lunds Technical University.

44. OGP. (2010). *Riser & pipeline release frequencies*. International Association of Oil & Gas Producers, Report No. 434-4.

45. OLF. (2004). *Application of EIV 61508 and IEC 61511 in the Norwegian Petroleum Industry*. The Norwegian Oil Industry Association, No: 070, Revision no: 02.

46. OREDA. (2009). *OREDA Offshore Reliability Data: Vol. 2. Subsea Equipment*. Trondheim, Norway: OREDA Participants: BP Exploration Operating Company Ltd, CococoPhillips Skandinavia AS, Eni S.p.A. Exploration & Production Division, ExxonMobil Production Company, Shell Global Solutions UK, Statoil ASA, Total S.A, Prepared by SINTEF Technology and Society.

47. Overview of the petroleum industry. [Web page], Available at: http://www.youtube.com/watch?v=IdcC5v4JQRw&list=PL67FCEC1098057C0A
Accessed: June, 2013

48. Petroleumtillsynet, (2010). *Norsok standard Z-013, Risk and emergency preparedness assessment*. Norway: Lysaker.

49. SINTEF. (2011). *Barriers to prevent and limit acute releases to sea.* Report No. A20727.

50. Sweco. *Miljöeffekter av olja.* [Web page]. Available at: http://www.sweco.se/sv/Sweden/Temp/Oljejouren/Miljoeffekter/
Accessed: July, 2013

51. Sweco. *Påverkan på växt- och djurliv*. [Web page]. Available at: http://www.sweco.se/sv/Sweden/Temp/Oljejouren/Miljoeffekter/Paverkan-pa-vaxt--och-djurliv/
Accessed: July, 2013

52. Sweco. *Återhämtning.* [Web page]. Available at: http://www.sweco.se/sv/Sweden/Temp/Oljejouren/Miljoeffekter/Aterhamtning/
Accessed: July, 2013

53. Trading Economics. *Euro Area inflation Rate.* [Web page]. Available at: http://www.tradingeconomics.com/euro-area/inflation-cpi

54. Universiti Teknologi, Malaysia. Faculty of Petroleum & Renewable Energy Eng. *Drilling engineering - Formation pressures.* [Web page]. Available at: ocw.utm.my/mod/resource/view.php?id=606
Accessed: July, 2013

55. US EPA. (2011). *Crude Oil Category Category Assessment Document.* The American Petroleum Institute Petroleum HPV Testing Group.

56. U.S. Nuclear Regulatory Commission Office of Nuclear Regulatory Research Washington. (2005). *The SPAR-H Human Reliability Analysis Method*. U.S.A: Idaho National Laboratory

57. PARLOC 2001. (2003). *The Update of Loss of Containment Data for Offshore Pipelines*. The Health and Safety Executive, The UK Offshore Operators Association and The Institute of Petroleum.

58. Vinnem, J.E. (2007). *Offshore Risk Assessment*. Stavanger Oslo: Springer.

# Appendix A - Validation of the model

In this chapter, the model is validated. It is an important step in ensuring that the model provides creditable output. The chapter is also intended to be a guideline for new users, since it shows how to apply all data presented in the previous chapters. This chapter will be divided into five main steps:

- Step 1: This section comprises a description of the system design and its protection layers. Furthermore, the LOPA credit for each present IPL and the system base failure frequency are determined.
- Step 2: The modified correction factor is determined by using tables and the information gained in the previous step (Step1). The initiating cause identification process is performed when Table 24 and Table 25 is filled in.
- Step 3: In this step, the system specific failure frequency is determined. In that work, the modified correction factor and the system specific base failure frequency are important input parameters.
- Step 4: A simplified consequence analysis is performed in order to measure the safety, environmental and commercial impact.
- Step 5: The SIL requirements for all SIFs are determined by using LOPA SIL-determination methods.

### A.1 Step1 - Description of the system and base failure frequency

The hypothetical system is organized as a single satellite well which produces direct to the surface through a 20 km pipeline linked to a semi-submersible topside facility, see Figure 34. The Xmas tree is a heavy subsea horizontal Xmas tree, equipped with three isolation valves where each valve is independently capable of shutting in the well. Next to the Xmas tree, a basic process control system choke is located for managing the hydrocarbon flow. The choke is a single unit capable to stop the hydrocarbon flow.

The Xmas tree is connected to the manifold structure by a two kilometres pipeline. The manifold is protected by a template and, due to future field expansion, it provides three open connectors. The manifold in turn is connected to the steel riser installation by an 18 kilometres pipeline. A natural well flow rate is present, whereupon no additional pumping equipment is needed. The last possibility of limiting the flow is by the subsea isolation valve, located at the beginning of the riser tube. The pipelines are made of high grade steel all the way from the riser to the Xmas tree. The whole 20 km pipeline is equipped with strong cathodic protection, i.e. corrosion protective design, which is assumed to significantly decrease corrosion damage. The two kilometres part of the pipeline, stretching from the Xmas tree to the manifold installation, have an inherently pressure safe design. That pipeline part is therefore less vulnerable for critical plugs/stopped-flow. However, the 18 km pipeline from the manifold to the riser, and the steel riser installation itself, are not designed to withstand full wellbore pressure. Therefore, a HIPPS is installed next to the manifold in order to automatically close the hydrocarbon flow if the pressure reaches a critical level.

In addition, pressure and temperature sensors and alarms will inform an operator if abnormal process condition occurs. Erosion sensors and leakage detectors are other warning systems which rely on operator actions. Both erosion sensors and leakage detectors are of latest technology and placed at critical spots in order to protect Xmas tree, pipelines, manifold structure and the steel riser installation. The subsea system design and the present protection layers are summarized in

Table 22 and Table 23.

**Table 22 Subsea system description summary**

| Unit | Description |
|---|---|
| Wellhead & Xmas tree | 1 (All types |
| Pipeline | 20 km<br>18 km, not inherently pressure safe design<br>2 km, inherently pressure safe design<br>1 pipeline in safety zone |
| Manifold | 1 (All types)<br>1 Template<br>3 open connections |
| Riser of steel | Diameter < 16” |

**Table 23 Description of protection layers and their LOPA credit**

| PL | Protection Layer | LOPA Credit | Comments |
|---|---|---|---|
| 1 | Pressure Safe Design | 0.01 | 2 km pipeline from Xmas tree to manifold and the manifold is designed to withstand full wellbore pressure. The riser and 18 km pipeline are not pressure safe designed. |
| 2 | Corrosion Protective Design | 0.5 | All pipelines are protected by cathodic protection which is assumed to be twice as effective than average. |
| 3 | Buried and/or trenched pipelines | 1.0 | The external impact protection is assumed to be equal as the North Sea average. |
| 4 | Template | 0.5 | A template protecting the manifold structure is present. Since the template is of good quality, it is given credit 0.5. |
| 5 | High grade steel in pipelines | 0.9 | All pipelines are of high grade steel. The LOPA group has decided to use LOPA credit 0.9, even though the pipeline is more than 5 km long. |
| 6 | High Pressure Trip, HIPPS | 1.0 | The HIPPS are situated right after the manifold structure, protecting 18 km pipeline and the steel riser installation. The preventive high pressure function is not given any credit as a conservative assumption. |
| 7 | Low Pressure Trip, HIPPS | SIL1-SIL3 | |
| 8 | Isolation of riser, SSIV | SIL1-SIL3 | |
| 9 | Isolation of subsea well | SIL1-SIL3 | |
| 10 | Choke | 1.0 | Since there are only one choke available, located shortly after the Xmas tree, a credit of 1.0 were decided. |
| 11 | Erosion Sensors | 0,9 | Erosion sensors are placed at the Xmas tree and the pipelines. Since the LOPA credit is coupled with uncertainty, the value 0.9 was chosen. |
| 12 | Abnormal Pressure and Temperature Alarm | 1.0 | The safety function is assumed to be of average performance. |
| 13 | Leakage detector | 0.4 | Since the subsea system is equipped with the latest leakage detection technology, the lowest credit is chosen. The detectors are in place at all subsea structures. |

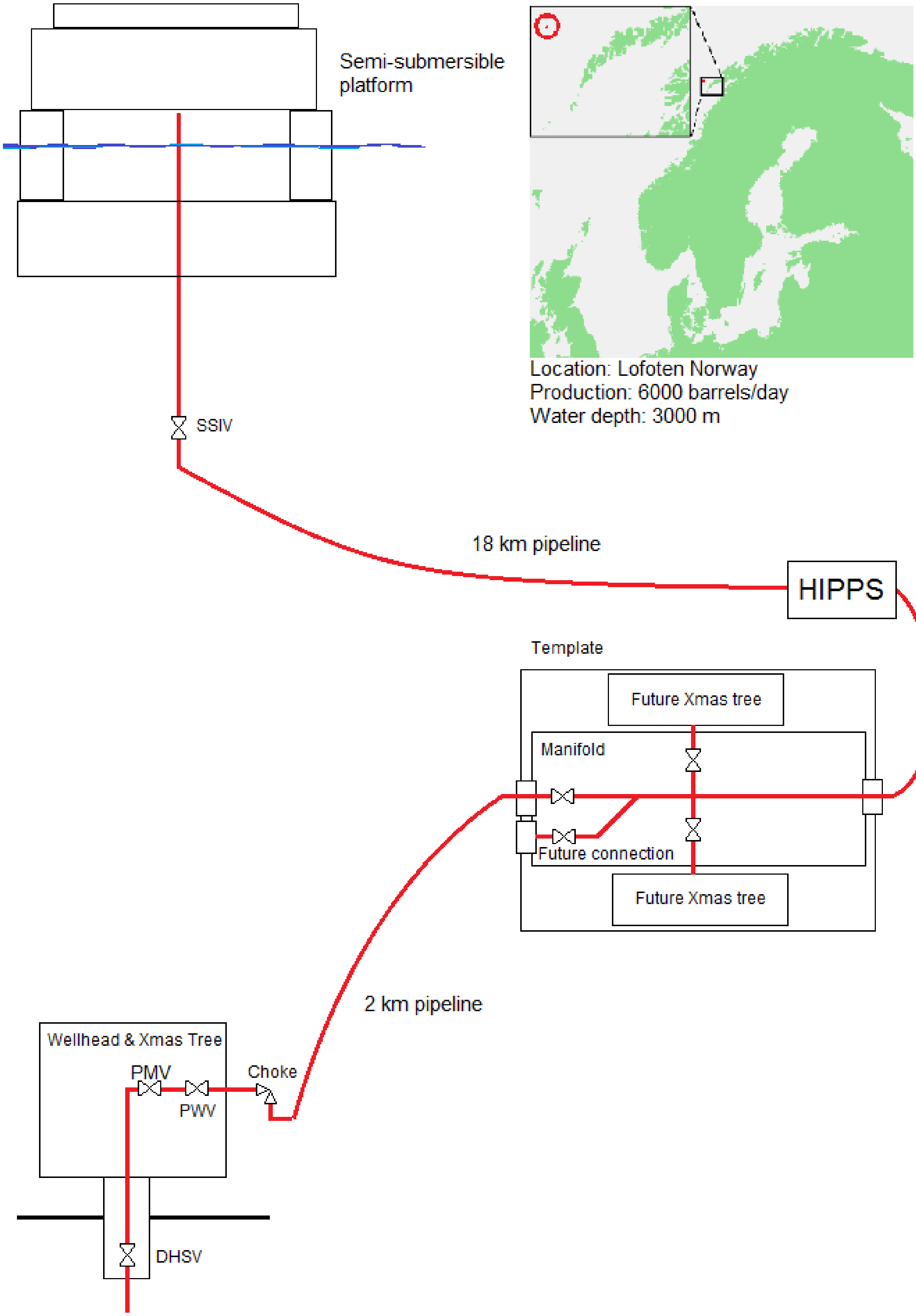


**Figure 34 Show a simplified subsea system and all present protection layers (Illustration: Christoffer Clarin)**

**A1.1 System specific base failure frequency**
The base failure frequency is here adapted into a specific subsea system. Note that the frequencies are still generic in their nature, but specific subsea system properties such as layout are taken into consideration. More detailed information about the equations used is found in chapter 4. All further equation numbers are referred to the equations presented in previous chapters.

Subsea unit failure frequencies:

(Equation 3): $F_{Pipelines} = \left[20 \cdot 50 \cdot 10^{-5} + (1 \cdot 0.5 \cdot 79 \cdot 10^{-5})\right] = 1040 \cdot 10^{-5}$/year

(Equation 2): $F_{manifold} = \left[(1/4 \cdot 1) \cdot 596 \cdot 10^{-5} + \left(3 \cdot 79 \cdot 10^{-5}\right)\right] = 386 \cdot 10^{-5}$/year

(Equation 5) $F_{B.subsea\ system} = F_{B.manifold} + F_{B.pipelines} + F_{B.riser} + F_{B.Wellhead\ \&\ Xmas\ tree} = 1899 \cdot 10^{-5}$/year

$F_{Wellhead\ \&\ Xmas\ tree} = 342 \cdot 10^{-5}$ /year

$F_{Riser} = 91 \cdot 10^{-5}$ /year

Pipeline failures in safety zone:

(Equation 4) $F_{P.SafetyZone} = 1 \cdot 0.5 \cdot (50 + 79) \cdot 10^{-5} = 65 \cdot 10^{-5}$ /year

## A.2 Step 2 - Determination of modified correction factor

The modified correction factor is determined by using Table 24 and Table 25. All green columns shall be set within the LOPA group.

**Table 24 Table for determination of the modified correction factor**

| Scenario | Initiating causes | Base Failure fraction | Frequency Correction Factor (GoM examples) | PL1 | PL2 | PL3 | PL4 | PL5 | PL6 | PL7 | PL8 | PL9 | PL10 | PL11 | PL12 | PL13 | Modified Correction Factor, $M_{CF}$ |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Damage of pipelines and flowlines | Corrosion | 0.40 | 1.0 | | 0.5 | | | 0.9 | | (?)<br>SIL | | (?)<br>SIL | 1.0 | | 1.0 | 0.4 | 0.072 |
| | External loads | 0.26 | 5.0 | | | 1.0 | | 0.9 | | (?)<br>SIL | | (?)<br>SIL | 1.0 | | 1.0 | 0.4 | 0.468 |
| | Material | 0.15 | 1.0 | | | | | 0.9 | | (?)<br>SIL | | (?)<br>SIL | 1.0 | | 1.0 | 0.4 | 0.054 |
| | Natural Hazards | 0.05 | 1.0 | | | | | 0.9 | | (?)<br>SIL | | (?)<br>SIL | 1.0 | | 1.0 | 0.4 | 0.018 |
| | Structural | 0.02 | 1.0 | | | | | 0.9 | | (?)<br>SIL | | (?)<br>SIL | 1.0 | | 1.0 | 0.4 | 0.007 |
| | Additional hazards | 0.12 | 0.8 | | | | | 0.9 | | (?)<br>SIL | | (?)<br>SIL | 1.0 | 0.9 | 1.0 | 0.4 | 0.031 |
| | Plugs / Stopped-flow | 0.5 | 1.5 | 0.9[1] | | | | | 1.0 | (?)<br>SIL | | (?)<br>SIL | 1.0 | | 1.0 | 0.4 | 0.270 / **0.920** |
| Destruction of Well head and/or Xmas tree | Corrosion | 0.40 | 1.0 | | 0.5 | | | | | | | (?)<br>SIL | | | 1.0 | 0.4 | 0.080 |
| | External loads | 0.26 | 5.0 | | | | 1.0 | | | | | (?)<br>SIL | | | 1.0 | 0.4 | 0.520 |
| | Material | 0.15 | 1.0 | | | | | | | | | (?)<br>SIL | | | 1.0 | 0.4 | 0.060 |
| | Natural Hazards | 0.05 | 1.0 | | | | | | | | | (?)<br>SIL | | | 1.0 | 0.4 | 0.02 |
| | Structural | 0.02 | 1.0 | | | | | | | | | (?)<br>SIL | | | 1.0 | 0.4 | 0.008 |
| | Additional hazards | 0.12 | 0.8 | | | | | | | | | (?)<br>SIL | | 0.9 | 1.0 | 0.4 | 0.035 / **0.723** |

[1] The LOPA credit is set to 0.9 since 10% of the pipeline is considered inherently pressure safe.

**Table 25 Table for determination of the modified correction factor**

| Scenario | Initiating causes | Base Failure fraction | Frequency Correction Factor (GoM examples) | PL1 | PL2 | PL3 | PL4 | PL5 | PL6 | PL7 | PL8 | PL9 | PL10 | PL11 | PL12 | PL13 | Modified Correction Factor, $M_{CF}$ |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Manifold collapse | Corrosion | 0.40 | 1.0 | | 0.5 | | | | | | | (?) SIL | 1.0 | | 1.0 | 0.4 | 0.08 |
| | External loads | 0.26 | 5.0 | | | | 0.5 | | | | | (?) SIL | 1.0 | | 1.0 | 0.4 | 0.260 |
| | Material | 0.15 | 1.0 | | | | | | | | | (?) SIL | 1.0 | | 1.0 | 0.4 | 0.060 |
| | Natural Hazards | 0.05 | 1.0 | | | | | | | | | (?) SIL | 1.0 | | 1.0 | 0.4 | 0.020 |
| | Structural | 0.02 | 1.0 | | | | | | | | | (?) SIL | 1.0 | | 1.0 | 0.4 | 0.008 |
| | Additional hazards | 0.12 | 0.8 | | | | | | | | | (?) SIL | 1.0 | 0.9 | 1.0 | 0.4 | 0.035 |
| | Plugs / Stopped-flow | 0.5 | 1.5 | 0.01 | | | | | | | | (?) SIL | 1.0 | | 1.0 | 0.4 | 0.003 / **0.466** |
| Rupture of riser | Corrosion | 0.40 | 1.0 | | 0.5 | | | | | (?) SIL | (?) SIL | (?) SIL | 1.0 | | 1.0 | 0.4 | 0.080 |
| | External loads | 0.26 | 5.0 | | | | | | | (?) SIL | (?) SIL | (?) SIL | 1.0 | | 1.0 | 0.4 | 0.520 |
| | Material | 0.15 | 1.0 | | | | | | | (?) SIL | (?) SIL | (?) SIL | 1.0 | | 1.0 | 0.4 | 0.060 |
| | Natural Hazards | 0.05 | 1.0 | | | | | | | (?) SIL | (?) SIL | (?) SIL | 1.0 | | 1.0 | 0.4 | 0.020 |
| | Structural | 0.02 | 1.0 | | | | | | | (?) SIL | (?) SIL | (?) SIL | 1.0 | | 1.0 | 0.4 | 0.008 |
| | Additional hazards | 0.12 | 0.8 | | | | | | | (?) SIL | (?) SIL | (?) SIL | 1.0 | 0.9 | 1.0 | 0.4 | 0.035 |
| | Plugs / Stopped-flow | 0.5 | 1.5 | 1.0 | | | | | 1.0 | (?) SIL | (?) SIL | (?) SIL | 1.0 | | 1.0 | 0.4 | 0.300 / **1.023** |
| Topside Blowout | | | 0.5-2.0 | | | | | | (?) SIL | (?) SIL | (?) SIL | (?) SIL | 1.0 | | 1.0 | | |

The base failure fraction is a generic failure distribution based on pipeline leakages in the North Sea. In this case, the platform is located in the Norwegian Lofoten area and some modifications have to be made. All changes are discussed within the LOPA group.

- *External loads:* There is assumed to be an increased frequency of "external load" damage, since there are a large quantity of fishing activity in the area and an increased risk for iceberg impact. The failure fraction is five doubled.
- *Additional hazards:* The frequency for "additional hazards", e.g. sabotage, fire & explosions, erosion and marine growth, is assumed to be lower than North Sea average and is therefore set to 0.8. It is motivated by the low hydrocarbon production flow rate, which decreases the damage caused by erosion. Furthermore, it is an inaccessible location for terrorists and the cold water temperature decreases marine growth.
- *Plugs / Stopped-flow:* The cold water temperature increases the frequency for plugs/stopped-flow. The failure rate correction factor is set to 1.5 in those cases where an inherently pressure safe design is not present.

When the failure rate correction factor is set, the LOPA group shall take specific subsea design and protection layers into account. All initiating causes are multiplied with each affecting protection layers LOPA credit. All results are being summarized, forming the unit specific modified correction factor

### A.3 Step 3 - Adapt a system specific failure frequency

In this step, the modified correction factor and the subsea system properties are taken into account when to estimate the specific failure frequency. The base failure frequency is summarized in Table 26 . The total failure frequency is calculated by the equations below:

**Table 26 Base failure frequencies. The original tables are found in chapter 4**

| Equipment class | Failure | Failure rate / Year [$10^{-5}$] | T [Hours] |
|---|---|---|---|
| Wellhead & Xmas tree [All types] | External leakage | 342 | 124 |
| Manifold [All types] | External leakage | 596 | 126 |
| Manifold [All types] | Free open connectors | 79 | 126 |
| Pipeline in open sea | External loads in safety zone | 79 | 24 |
| Riser of steel ≤ 16" | External leakage | 91 | 168 |
| **Equipment class** | **Failure** | **Failure rate / km · year [$10^{-5}$]** | **T [Hours]** |
| Pipeline in open sea | External leakage | 50 | 24 |

Subsea unit specific failure frequency (SF = Specific frequency):

(Equation 6) $F_{\text{Wellhead \& Xmas tree}} = 342 \cdot 0.723 \cdot 10^{-5} \approx 247 \cdot 10^{-5}$ /year

(Equation 7) $F_{\text{pipelines}} = 1040 \cdot 0.92 \cdot 10^{-5} \approx 956 \cdot 10^{-5}$ /year

(Equation 8) $F_{\text{manifold}} = 386 \cdot 0.466 \cdot 10^{-5} \approx 180 \cdot 10^{-5}$ /year

(Equation 9) $F_{\text{Riser}} = 91 \cdot 1.023 \cdot 10^{-5} \approx 93 \cdot 10^{-5}$ /year

(Equation 10) $F_{\text{Subsea system}} = 1476 \cdot 10^{-5}$ /year

$M_{\text{CF-P.SafetyZone}}$ is set to 0.5. Few ships is assumed to enter the safety zone.
(Equation 11) $F_{\text{P.SafetyZone}} = 0.5 \cdot 65 \cdot 10^{-5} = 33 \cdot 10^{-5}$ /year

### A.4 Step 4 – Consequence analysis

Risk is defined as a combination of frequency and consequences. In this thesis, the consequences are divided into commercial, environmental and safety impact.

#### A.4.1 Oil spill amount – Environmental and commercial impact

In order to measure the environmental and commercial impact the total oil spill amount has to be estimated. Table 27 can be used in order to fill in all necessary data needed for calculating the total mass released for different scenarios. All green marked columns in the table shall be filled in by the user. What these columns mean are listed below:

- frequency [$10^{-5}$]: (Subsea unit specific failure frequency [$10^{-5}$] ) · (hole size fraction [%] )
- **T** [Hours]: (maintenance time, T ) · (correction factor, $T_{CF}$)
- $\dot{m}$ [Tonnes/h] : From Table 28 or calculated by use of equation 14
- $m_{tot}$ [Tonnes]: (mass flow) · (Leakage duration time)

The specific failure frequency for different subsea units were determined in the previous step. By hole size fraction (see Table 27) with the average maintenance time for different subsea units (see Table 26 ), the oil spill duration time can be estimated. The maintenance time correction factor shall be determined by the LOPA expert group. In this example, it is set to 5 due to water depth 3000 meters and an inaccessible location.

**Table 27 Hole sizes and hole size fraction according to Table 16**

| Hole Size [Diameter] | Subsea Pipeline [%] | Riser [%] | Area [$m^2$] |
|---|---|---|---|
| Full rupture, 16” | - | 12 | $400 \cdot 10^{-4} \pi$ |
| Full rupture, 8” | 8 | - | $100 \cdot 10^{-4} \pi$ |
| Large 100mm | 2 | 13 | $25 \cdot 10^{-4} \pi$ |
| Significant 80 | 8 | 7 | $16 \cdot 10^{-4} \pi$ |
| Medium 50mm | 8 | 8 | $6{,}25 \cdot 10^{-4} \pi$ |
| Small 20mm | 74 | 60 | $1 \cdot 10^{-4} \pi$ |
| Average pipeline | 100 | - | $11 \cdot 10^{-4} \pi$ |
| Average riser | - | 100 | $53 \cdot 10^{-4} \pi$ |

The massflow can approximately be estimated by using Table 28. The only input needed is the differential pressure, which in this example is set to 50 bar. However, long pipelines with high flow velocity may cause a significant pressure drop due to friction. The pressure drop can be calculated by using the equation 14 in section 7.2.1. However, in this example the pipeline friction loss become negligible, if rupture is assumed to occur 7 km from the hydrocarbon source.

**Table 28 Massflow according to Table 19**

| | Massflow, $\dot{m}$ [tonnes/h] | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| $\Delta P$ [Bar] | Small | Medium | Significant | Large | Rupture, 8” | Rupture, 16” | Average Pipeline | Average Riser1 |
| 25 | 17 | 104 | 267 | 417 | 1666 | 6665 | 183 | 883 |
| 30 | 18 | 114 | 292 | 456 | 1825 | 7301 | 201 | 967 |
| 35 | 20 | 123 | 315 | 493 | 1972 | 7886 | 217 | 1045 |
| 40 | 21 | 132 | 337 | 527 | 2108 | 8431 | 232 | 1117 |
| 45 | 22 | 140 | 358 | 559 | 2236 | 8942 | 246 | 1185 |
| **50** | **24** | **147** | **377** | **589** | **2356** | **9426** | **259** | **1249** |

### A.4.1.1 Scenario specific oil spill size

The scenario specific oil spill size can be calculated by filling in Table 29. In this example the table is already filled in for educational purpose.

**Table 29 Show oil spill amount for different hole sizes**

| Equipment class | Hole size [$m^2$] | | [%] | Frequency [$10^{-5}$] | $\dot{m}$ [Tonnes/h] | **T** [Hours] | $m_{tot}$ [Tonnes] |
|---|---|---|---|---|---|---|---|
| Wellhead & Xmas tree | Full rupture | $100 \cdot 10^{-4}$ | 8 | 19.8 | 2356 | 5·124 620 | 1 460 720 |
| | Large | $25 \cdot 10^{-4}\pi$ | 2 | 4.9 | 589 | | 365 180 |
| | Significant | $16 \cdot 10^{-4}\pi$ | 8 | 19.8 | 377 | | 233 740 |
| | Medium | $6{,}25 \cdot 10^{-4}\pi$ | 8 | 19.8 | 147 | | 91 140 |
| | Small | $1 \cdot 10^{-4}\pi$ | 74 | 182.8 | 24 | | 14 880 |
| Manifold | Full rupture | $100 \cdot 10^{-4}$ | 8 | 14.4 | 2356 | 5·126 630 | 1 484 280 |
| | Large | $25 \cdot 10^{-4}\pi$ | 2 | 3.6 | 589 | | 371 070 |
| | Significant | $16 \cdot 10^{-4}\pi$ | 8 | 14.4 | 377 | | 237 510 |
| | Medium | $6{,}25 \cdot 10^{-4}\pi$ | 8 | 14.4 | 147 | | 92 610 |
| | Small | $1 \cdot 10^{-4}\pi$ | 74 | 133.2 | 24 | | 15 120 |
| Pipelines | Full rupture | $100 \cdot 10^{-4}$ | 8 | 76.5 | 2356 | 5·24 120 | 282 720 |
| | Large | $25 \cdot 10^{-4}\pi$ | 2 | 19.1 | 589 | | 70 680 |
| | Significant | $16 \cdot 10^{-4}\pi$ | 8 | 76.5 | 377 | | 45 240 |
| | Medium | $6{,}25 \cdot 10^{-4}\pi$ | 8 | 76.5 | 147 | | 17 640 |
| | Small | $1 \cdot 10^{-4}\pi$ | 74 | 707.4 | 24 | | 2880 |
| Riser of steel | Full rupture | $400 \cdot 10^{-4}$ | 12 | 11.2 | 2356[1] | 5·168 840 | 1 979 040 |
| | Large | $25 \cdot 10^{-4}\pi$ | 13 | 12.1 | 589 | | 494 760 |
| | Significant | $16 \cdot 10^{-4}\pi$ | 7 | 6.5 | 377 | | 316 680 |
| | Medium | $6{,}25 \cdot 10^{-4}\pi$ | 8 | 7.4 | 147 | | 123 480 |
| | Small | $1 \cdot 10^{-4}\pi$ | 60 | 55.8 | 24 | | 20 160 |

[1]Only one pipeline is linked to the riser. A riser rupture cannot have a higher massflow due to mass balance.

### A.4.1.2 Scenario specific safety risk

The frequency of a hazardous event depends on:

- Specific pipeline leakage frequency in the safety zone, $F_{P.SafetyZone} = 65 \cdot 10^{-5}$ /year
- Specific riser leakage frequency, $93 \cdot 10^{-5}$ /year
- Specific topside blowout frequency

The specific topside blowout frequency can be calculating by using equation 20. The other bullet points are already known due to calculations in step 3.

(Equation 20) $F_{T.Blowout\ specific} = F_{B.T\text{-}blowout} \cdot A_2 = 7.84 \cdot 10^{-6}$ /year

$A_2$: The topside blowout adjustment factor is set to 0.8 according to qualitative judgement
$F_{B.T\text{-}blowout}$: Base failure frequency per well · year, $9.8 \cdot 10^{-6}$/year

The hazard distribution is set to:

$D_{(10\ injuries)} = 0.30$ $D_{(1\ perm.injury)} = 0.20$ $D_{(1\ fatalitiy)} = 0.3$
**$D_{(1\text{-}10\ fatalities)}$ = 0.16** $D_{(>10\ fatalities)} = 0.01$

Finally, the safety risk can be determined by equation 21.
(Equation 21) Safety risk = $(F_{T.Blowout\ specific} + F_{P.SafetyZone} + F_{riser}) \cdot A_1 \cdot D = 2.0 \cdot 10^{-6}$ /year

$A_1$ = Ignition probability, 0.008
D = Consequence distribution, e.g. $D_{(1\text{-}10\ fatalities)} = 0.16$

### A.5 Step 5 - SIL determination

The consequences are divided into environmental, commercial and safety impact. The risk reduction factor is calculated by dividing the subsea system failure frequency by the acceptable risk value. ERAC, TMEL and CRAC are determined according to chapter 5. The ERAC value can be adjusted to specific circumstances by using a correction factors, which is determined by three question with a "yes" or "no" answer. More yes-answers mean higher safety requirements. In this example, one "yes" is used leading to twice the standard safety requirements. The CRAC value is based on the average regional cost per release, on a per-tonne basis. In this example, the CRAC for the European region is used.

By using the equations presented below, the required risk reduction, RR, is calculated. A RR-value below one is considered acceptable. Three different IPLs are taken into account when to determine the necessary SIL. These protection layers are listed in Table 30.

**Table 30 Show which IPLs to be SIL determined.**

| | Independent Protection Layer | Function |
|---|---|---|
| SIL(X)<br>IPL9 | Subsea ESD<br>DHSV, PMV, PWV | Isolation of subsea well |
| SIL(Y)<br>IPL7 | Subsea PSD<br>HIPPS, mitigating function | Isolation of pipeline and riser installation |
| SIL(Z)<br>IPL8 | Subsea ESD<br>Subsea Isolation Valve | Isolation of riser installation |

### B.5.1 Environmental Impact

In this example, only consequence 4 and consequence 5 events seem to occur due to the scenario specific releases of oil. The release amount for each scenario can be found in Table 29. The calculation process below is based on the equations presented in section 7.3. SIL(X) represents the "isolation of well function", SIL(Y) represents the Subsea HIPPS and SIL(Z) represents the "isolation of riser function", as described in Table 30.

*Consequence 5 >10 000 tonnes:*

$$RR5 = \frac{SIL(X)\left(F_{\text{Wellad \& Xmas tree}} + F_{\text{Manifold}} + SIL(Y)\left(F_{\text{Pipeline}} + (SIL(Z) \cdot F_{\text{Riser}})\right)\right)}{ERAC_5 \cdot CF_{ERAC}}$$

$F_{\text{wellhead \& Xmas tree}}$ $= 247 \cdot 10^{-5}$/year
$F_{\text{Manifold}}$ $= 180 \cdot 10^{-5}$/year
$Y$ $= 0.1$
$F_{\text{Pipelines}}$ $= (956\text{-}707) \cdot 10^{-5}$/year
$F_{\text{riser}}$ $= 93 \cdot 10^{-5}$ /year
$ERAC_5$ $= 10^{-5}$ [Table 7]
$CF_{ERAC}$ $= 0,5$

Result:
SIL(X) = 3 (0.0005)
SIL(Y) = 1 (0,1)
SIL(Z) = 1 (0,1)
→ RR = 0,45 **OK**

*10 000 tonnes > Consequence 4 > 1000 tonnes:*

$$RR4 = \frac{SIL(X) \cdot SIL(Y) \cdot F_{\text{Pipelines}}}{ERAC_4 \cdot CF_{ERAC}}$$

$F_{\text{pipelines}}$ $= 707 \cdot 10^{-5}$/year
$ERAC_4$ $= 10^{-4}$ [Table 7]
$CF_{ERAC}$ $= 0.5$

Results1:
SIL(X) = 1 (0.05)
SIL(Y) = 1 (0.1)
→ RR=0.71 **OK**

Result 2:
SIL(X) = 2 (0.005)
→ RR=0.71 **OK**

### A.5.2 Commercial impact

If using the CRAC for the European region, the consequence classes are categorized as shown in Table 31. All red cells in Table 29 right column are considered as $CRAC_5$ events, all yellow are $CRAC_4$ events and all light blue are considered as $CRAC_3$ events.

**Table 31 CRAC for the European region**

| Consequence class | | Commercial losses [$10^6 \cdot \$$] | Corresponding release quantity of oil [$10^3 \cdot$ Tonnes] |
|---|---|---|---|
| 3 | Significant cost | 100-1000 | 3-30 |
| 4 | Serious cost | 1000-10 000 | 30-300 |
| 5 | Major cost | >10 000 | >300 |

$$RR5 = \frac{SIL(X)\left(F_{Wellad\ \&\ Xmas\ tree}+F_{Manifold} + SIL(Y)\left(F_{Pipeline}+(SIL(Z)\cdot F_{Riser})\right)\right)}{CRAC_5}$$

| | | |
|---|---|---|
| $F_{wellhead\ \&\ Xmas\ tree}$ | $= 24.7 \cdot 10^{-5}$/year | Result: |
| $F_{Manifold}$ | $= 18.0 \cdot 10^{-5}$/year | SIL(X) = 2 (0,002) |
| $F_{riser}$ | $= 29.8 \cdot 10^{-5}$/year | SIL(Y2) = 1 (0.1) |
| $CRAC_5$ | $= 10^{-6}$ | SIL(Z) = 1 (0.1) |
| | | RR → 0.86 **OK** |

$$RR4 = \frac{SIL(X)\left(F_{Wellad\ \&\ Xmas\ tree}+F_{Manifold} + SIL(Y)\left(F_{Pipeline}+(SIL(Z)\cdot F_{Riser})\right)\right)}{CRAC_4}$$

| | | |
|---|---|---|
| $F_{wellhead\ \&\ Xmas\ tree}$ | $= 39.6 \cdot 10^{-5}$/year | Result: |
| $F_{Manifold}$ | $= 28.8 \cdot 10^{-5}$/year | SIL(X) = 2 (0,005) |
| $F_{Pipelines}$ | $= 172.1 \cdot 10^{-5}$/year | SIL(Y2) = 1 (0.1) |
| $F_{riser}$ | $= 7.4 \cdot 10^{-5}$/year | SIL(Z) = 1 (0.1) |
| $CRAC_4$ | $= 10^{-5}$ | RR → 0.43 **OK** |

$$RR3 = \frac{SIL(X)\left(F_{Wellad\ \&\ Xmas\ tree}+F_{Manifold} + SIL(Y)\left(F_{Pipeline}+(SIL(Z)\cdot F_{Riser})\right)\right)}{CRAC_3}$$

| | | |
|---|---|---|
| $F_{wellhead\ \&\ Xmas\ tree}$ | $= 182.8 \cdot 10^{-5}$/year | Result: |
| $F_{Manifold}$ | $= 133.2 \cdot 10^{-5}$/year | SIL(X) = 1 (0,02) |
| $F_{Pipelines}$ | $= 783.9 \cdot 10^{-5}$/year | SIL(Y2) = 1 (0.1) |
| $F_{riser}$ | $= 55.8 \cdot 10^{-5}$/year | SIL(Z) = 1 (0.1) |
| $CRAC_3$ | $= 10^{-4}$ | RR → 0.79 **OK** |

### A.5.3 Safety impact

*Scenario specific number of fatalities:*

In this example, the worst case of 10 fatalities is tested. The event frequency has already been determined in section A.4.1.2. According to the result, it seems that safety impact is small compared with environmental and the commercial impact. It seems logical since most of the subsea system is situated outside the safety zone.

$$RR = \frac{SIL(X) \cdot SIL(Y) \cdot SIL(Z) \cdot (1-\Theta) \cdot \text{Safety risk} + \Theta \cdot \text{safety risk}}{TMEL}$$

| | |
|---|---|
| $\Theta$ | = Fraction of immediate casualties, 0.5 |
| Safety risk | = $2.0 \cdot 10^{-6}$ /year causing 10 fatalities |
| TMEL | = $10^{-5}$, Table 6 |

Result:

SIL(X) = 1 (0.1)

→ 0.11 **OK**

# Appendix B - Cost benefit Analysis and consequence valuation in monetary terms

It is clear that an uncontrolled release of hydrocarbons can cause grave commercial, environmental and safety impact. By implementing series of preventive actions it is possible to reduce the likelihood of an incident and mitigate its consequences. In this appendix, a Cost-Benefit Analysis (CBA) is provided in order to managing a proper balance between safety measures and production. It is achieved by comparing the cost of an accident with the cost of implementing safety measures.

In order to do so, the cost of an incident has to be measured in monetary terms. Consequences are divided into the following categories.

- Environmental impact: Market cost and non-market cost
- Commercial impact: Clean-up cost and loss of production
- Safety impact: Cost coupled to number of fatalities

According to cost-benefit theory, a preventive action shall be implemented as long as the benefit of the actions exceeds its cost. How this comparison is performed is described in the end of this appendix. Not that this CBA does not intend to be the primary SIL-determination method but as a complementary method. The result shall not be used in order to motivate a lower SIL-rating, but well as motivating a higher SIL-rating.

### B.1 Input data

When using CBA, the average quantity of an oil release and the mean number of fatalities per year are important factors. These values can be determined by using the equations below. The results can be used as input when using the valuation-models presented in this chapter.

#### B.1.1 Average oil spill size

The average oil spill is calculated by multiplying the mean duration time by the hydrocarbon massflow. The equation has to be divided into two parts, the riser part and all other subsea units. The reason is due to the different hole size distribution, see Table 16. The mean duration time also differs between subsea units, whereupon the failure fraction has to be taken into account. The whole calculation procedure is shown in equation 25.

(Equation 25)

$$\text{Oil spill}_{AVG} = \left( \left(\frac{\text{F wellhead \& Xmas tree}}{\text{Fsubsea system}}\right) \mathrm{T}_{\text{wellhead\&Xmas tree}} + \left(\frac{\mathrm{F}_{\text{manifold}}}{\text{Fsubsea system}}\right) \mathrm{T}_{\text{Manifold}} + \left(\frac{\mathrm{F}_{\text{Pipelines}}}{\text{Fsubsea system}}\right) \mathrm{T}_{\text{Pipeline}} \right) \dot{m}_{AVG\ pipeline} + \left(\frac{\text{Friser}}{\text{Fsubsea system}}\right) \cdot \mathrm{T}_{Riser} \cdot \dot{m}_{AVG\ Riser}$$

| | |
|---|---|
| Oil spill $_{AVG}$ | = Average oil spill per year [Tonnes] |
| $F_{\text{wellhead \& Xmas tree}}$ | = Total release frequency for a specific wellhead & Xmas tree |
| $F_{\text{Manifold}}$ | = Total release frequency for a specific manifold |
| $F_{\text{Pipelines}}$ | = Total release frequency for a specific pipeline system |
| $F_{\text{riser}}$ | = Total release frequency for a specific riser installation |
| $F_{\text{subsea system}}$ | = Total release frequency for a specific subsea system |
| $T_{\text{units}}$ | = Oil leakage duration time, determined by equation 13 |
| $\dot{m}_{\text{AVG pipeline}}$ | = Determined by equation 14 or table 19 |
| $\dot{m}_{\text{AVG Riser}}$ | = Determined by equation 14 or table 19 |

### B.1.2 Average number of fatalities

The average number of fatalities per year is calculated by using equation 26. The fat-factors are qualitative estimate determined by the LOPA expert group. As a support for that judgement, Table 20 provides a list of factors which can affect the consequence. Furthermore, Table 32 show the average number of fatalities for an incident in the North Sea offshore industry /78/. These values do not have to correspond with reality, and the LOPA expert group shall fell free to set other quantities. Finally, the result can be calculated by using equation 26.

**Table 32 Average number of fatalities per event**

| Event | Fatalities / event |
|---|---|
| Topside blowout [$fat_{blowout}$] | 5.3 |
| Pipeline leakage [$fat_{Pipelines}$] | 4.1 |
| Riser leakage [$fat_{Riser}$] | 4.1 |

(Equation 26) $Fatalities_{Avg} = (F_{T.Blowout\ specific} \cdot fat_{blowouts} + F_{P.SafetyZone} \cdot fat_{pipelines} + F_{riser} \cdot fat_{riser}) \cdot A_1$

$A_1$: Ignition probability (See Table 20, D)

### B.2 Environmental Impact

In this section, environmental damage is valued in monetary terms. The cost is measured by dividing the environmental losses into two categories listed below. Finally, these terms are being summarized for estimating the total environmental value into monetary terms.

- *market costs:* Market costs mean direct economic losses due to affected fishery and hotel businesses
- non-market costs: Non-market cost, such as loss of clean water and lively fauna, is not yet priced. An additional method called contingent valuation is being used in order to estimate these losses.

### B.2.1 Ecosystem valuation

All ecosystems generate a flow of services. Without them human and other life on earth would not exist. In that perspective it is not possible to measure the total economic value. However, it is possible to valuate marginal changes in the asset. Ecosystem economist prefers to focus on those parts providing direct human benefit /2/. Such benefits are as listed below and shown in figure 35 /22/.

- Supporting ecosystem services: Foundation of primary production, habitats and natural dynamics.
- Regulating ecosystem services: Climate regulation due to the seas capacity to slow down accumulation of $CO_2$ in the atmosphere.
- Provisioning ecosystem services: Provision of food through fishing.
- Cultural ecosystem services: Recreational opportunities such as fishing, swimming, bird watching or lying at the beach.

In this thesis, costs due to environmental damage are divided into two categories. These are market costs, which include loss of profit and well fare losses for those dependent on affected natural resources, and non-market costs, which include those values and welfare losses not priced in the market /22/.

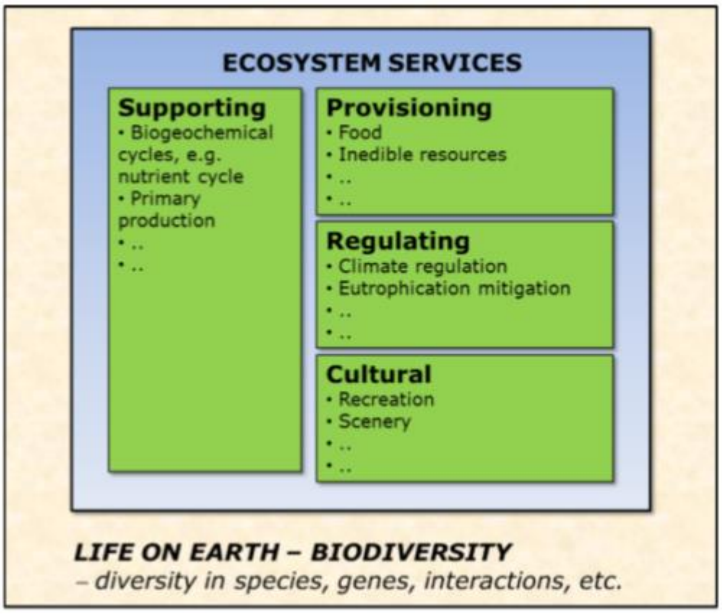


**Figure 35 Categories of ecosystem services /22/**

### B.2.2 Non-market costs

It is challenging to put a value at something not automatically priced on the free market. Clean and non-polluted water is such a case, and therefore additional methods have been developed /42/.

The two dominating methods are revealed preference valuation and stated preference method, also called contingent valuation. The first mentioned investigates the correlation between market priced products and value of the eco system, for example fishing-card and sea water quality /42/. The contingent valuation method uses questionnaires to count peoples willingness to pay, WTP, for an improvement help keeping the asset at status quo or willingness to accept, WTA, which measure how much people want to have in compensation for a degradation of the environment /2/. In this thesis only contingent valuation will be further evaluated.

The total measurable economic value, TEV, is the sum of all WTP and WTA. It can be divided into use, non-use and passive-use values. The use-values refer to the actual utilization of the asset in question. Use-values can be divided into actual use, planed use and possible use. An example of actual use can be swimming in the ocean. Planed and possible use depends on the willingness to pay to preserve the option for using the asset in future. The non-use values refer to the willingness to pay even though there is no actual, planned or possible use of the ecosystem. That value can be divided into existence value, altruistic value and bequest value. The existence value is the value to preserve the ecosystem even though it has no actual or planned use for anyone, and motivation can be concern for the nature itself. Altruistic value means the willingness to pay to let other people from the same generation have the opportunity of using the asset and the bequest value refers to the responsibility of keeping the asset to future generations /2/. The different values are shown in Figure 36.

TEV do not encompass intrinsic values, such as right to existence, which assets are unrelated to human preferences. Some critics of CBA mean that other species have “intrinsic rights” which cannot be measured in monetary terms. However, it can be argued that peoples willingness to pay is also influenced of their own judgement about intrinsic value /2/. It is also practical to measure all consequences in monetary terms, so that the good of preventive actions can be measured. If not putting a value of the environment non-market assets there is a possibility that it is not taken into consideration at all. The use of contingent valuation is therefore seen as a good approach.

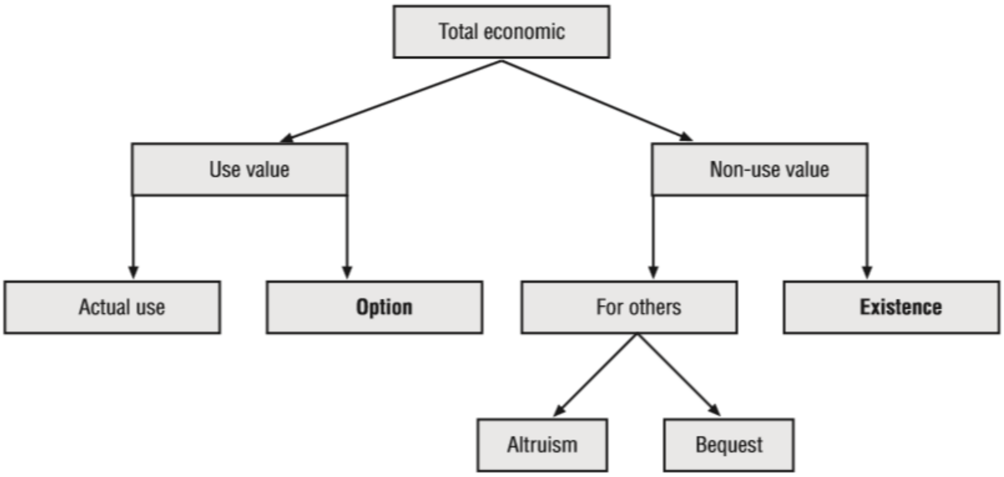


**Figure 36 Show the different parts of TEV /2/**

In the following section several studies using contingent valuation method are presented. Some of them are valuations of environmental costs from real disasters and other is hypothetic scenarios. All studies result in a value of the non-market asset.

*Prestige Oil Spill – Spain*
On November 13, 2002, the 26 year-old tanker Prestige suffered serious damage outside the Spanish coast. The ship carried 77 000 tonnes of heavy low- quality oil and sank after splitting into two during a storm on November 19. On its way down to the sea bed she spilled more than 60 000 tonnes of oil, polluting more than 1300 km coastline. The ecosystem was injured and a large amount of people, economically and culturally linked to the sea, were affected /38/.

A contingent valuation study measured the Spanish household's willingness to pay for an oil spill prevention program capable of preventing similar disasters in the future. By using a non-parametric Turnbull distribution it resulted in an average willingness to pay of 58,08 € per household. It results in a total value of about 574 million (2006) €. The loss of non-market values is thereby comparable with the direct economic losses due to fishery and tourism /38/.

*Exxon Valdez - Prince William Sound, Alaska U.S.A*
On the night the 24 march 1989 the oil tanker Exxon Valdez left the port Valdez in Alaska to reach open water. The ship left the normal sea lane in an attempt to avoid ice bergs, but instead ran in to submerged rocks /34/. 37 000 tonnes of crude was spilled out into the sound making it one of the worst environmental disasters in U.S. history /33/.

A contingent valuation investigation, in order to measure the American household's willingness to pay for an escort ship program in order to prevent such disaster in the future, resulted in a mean non-parametric Turnbull value of 79,20 (1990) U.S. dollar. By multiplying the number of English-speaking households by the median WTP an estimate of 2,8 billion dollars in lost passive use value was made. If the mean WTP would have been used instead the lost passive value would have increased to at least 4.87 billion dollars. Exxon had to pay 1 billion dollars in natural resource damage and had to spend over 2 billion dollars on oil spill response /5/. The overall costs for the company has reportedly been 4.3 billion dollar /33/.

*North Sea – Germany*
The North Sea is a shallow sea located in western part of Europe. In the southern part, along the German and partly the Danish and Dutch coast lays the Wadden Sea. The Wadden Sea has an important natural ecosystem with large populations of sea birds and mammals. The area is

therefore vulnerable to large scale oil spills. The “Pallas” accident in 1998, when 244 tonnes of heavy oil were released, killed almost 16 000 sea birds and the cost for emergency management and cleaning reached 15 million euros. The coast line is also a popular place for recreation activities, such as walking in nature, swimming and lying at the beach /35/.

A contingent valuation study was made to measure the German households’ willingness to pay for avoiding similar disasters in the future by paying for a specific combat management program. The presented scenario was that 100 tonnes of fuel where released at the same spot as the Pallas accident, and that the oil pollutant combat strategy wold be successful in its work. The result was an average willingness to pay of 29.1€ (2006). Multiplied with the total number of households in Germany it generated €1135 million /35/.

*North Sea – Belgium*
The Belgian North Sea coast has a length of 65 km. The coastline is important for regional and national economics and also for recreation and other non-market values. The Belgian coast is an unique ecological system with plenty of mammals and plant life diversity. An accidental oil spill is one of the biggest threats to that ecosystem /4/.

To measure the non-market welfare losses in monetary term a contingent valuation study was made in 2006. Three different scenarios was presented, light scenario with 200$m^3$ oil spill, moderate scenario with 5000$m^3$ oil spill and severe scenario with 10 000$m^3$ oil spill. The frequency of the scenarios varies in different questionnaire version, but it did not affect the total outcome so much. The results are here presented as a non-parametric Turnbull model approach and protest answers from people not willing to pay anything are excluded /4/.

| | | |
|---|---|---|
| Light scenario | 200$m^3$ oil spill | 116.81€ |
| Moderate scenario | 5000$m^3$ oil spill | 117.13€ |
| Severe scenario | 10 000$m^3$ oil spill | 135.99€ |

**B.2.3 Benefit transfer**
A definition of benefit transfer is: *“The transfer of existing estimates of non-market values to a new study which is different from the study for which the values were originally estimated”.* In general the transfer is less reliable than the original study. However, the reason for using it is obvious as it provides data without costly and time consuming original studies /2/. In this master thesis original studies are not an option.

When using benefit transfer defining the population is of major importance. The society is the sum of all individuals and it is hard to set the geographical boundaries. Even though it may be examples where the boundaries needs to be set at a global scale the usual society in CBA studies are the population/households within a country. Other parameters which may differ between the original study and policy cites, i.e. the area under consideration, are /2/:

- Socioeconomic and demographic characteristics of the population, including income, education and age.
- The physical characteristics of the study and policy site, such as environmental services and the good related to it.
- The change in provision between sites and the good to be valued. Improvements which provide small benefits may not apply to large scale changes. The WTP and quantity may not have a linear relationship.
- Differences in the market condition on the sites, e.g. the possibility of finding substitutes for the ecosystem services.
- Changes in valuation over time due to for example income changes or decreasing availability of clean water and unthreatened ecosystems.

In this thesis, socioeconomic and demographic differences are taken into account by converting the mean willingness to pay per household by multiplying it with the relative purchasing power. Relative purchasing power can easily be calculated by using values from Table 34. For instance, the relative purchasing power between Germany and Norway is 65.640/40.901 ≈ 1.61. Changes in time are accounted for due to inflation measurement. The inflation can be looked up for different countries, otherwise a slightly conservative multiplication factor of 1.03 per year is recommended due to the inflation rate of 2.25 % in euro zone from 1991 – 2013 /53/. Furthermore, only studies linked to western countries have been used due to assumed similarities in culture, age and education level. No model modifications have been made for estimating environmental damage in other parts of the world. First of all, modifications are hardly done since most contingent valuation studies are made in western countries after the Exxon Valdez disaster 1989. Secondly, if the model is used on less developed countries it would give a conservative high environmental value. As the majority of people in western countries no longer have to struggle at subsistence level, the acceptance for industrial activity is not as easy given as when people fight against hunger and poverty /24/. The equation for benefit transfer is presented as equation 26.

(Equation 26) $NMV = C \cdot CF \cdot PP \cdot IF \cdot PoP$

(Equation 27) $\overline{NMV} = \frac{\sum NMV_i}{i}$

NMV = Non-market value for a scenario
$\overline{\mathbf{NMV}}$ = Non-market value as an average, according to Table 33
C = Willingness to pay per household
CF = Currency factor
PP = Purchasing power
IF = Inflation factor
PoP = Population size [Households]

**Table 33 Example of benefit transfer into Norwegian conditions**

| Oil spill [Tonnes] | Country | C | CF (2013-07-22) | PP | IF | PoP | NMV Billion NOK |
|---|---|---|---|---|---|---|---|
| 100 | Germany | 29,1€ | 7,31 | 1,61 | 1,17(2006) | 2 259 000 | 0,91 |
| 172 | Belgium | 116,81€ | 7,31 | 1,65 | 1,17(2006) | 2 259 000 | 3,63 |
| 4300[1] | Belgium | 117,13€ | 7,31 | 1,65 | 1,17(2006) | 2 259 000 | 3,73 |
| 8600[1] | Belgium | 135,99€ | 7,31 | 1,65 | 1,17(2006) | 2 259 000 | 4,34 |
| 37 000[1] | U.S.A. | 79,20$ | 5,55 | 1,31 | 1,88(1990) | 2 259 000 | 2,45 |
| 60 000 | Spain | 58,08 € | 7,31 | 2,01 | 1,17(2006) | 2 259 000 | 2,26 |
| $\overline{NMV}$ | | | | | | | 2,89 |

[1] The oil spill amount in tonnes has been calculated by multiplying the volume with density $900kg/m^3$.

**Table 34 Purchasing power and number of households in countries**

| Country | Purchasing Power[1] | Households[3] | Country | Purchasing Power[1] | Households[3] |
|---|---|---|---|---|---|
| Norway | 65,640 | 2 259 000[3] | UK | 36,901 | 25 691 000 |
| Germany | 40,901 | 40 076 000 | Brazil | 11,909 | 57 324 167 |
| Belgium | 39,788 | 4 575 959 | Russia | 23,501 | 52 711 375 |
| Spain | 32,682 | 16 741 379 | Denmark | 42,086 | 2 547 377 |
| U.S.A | 49,965 | 117 538000 | Ghana | 2,048 | 5 921 000[4] |

[1] http://data.worldbank.org/indicator/NY.GDP.PCAP.PP.CD
[2] http://en.wikipedia.org/wiki/List_of_countries_by_number_of_households
[3] http://www.ssb.no/en/familie
[4] http://ww2.unhabitat.org/habrdd/conditions/wafrica/ghana.htm

As seen in Table 33, there are no correlation between the oil spill amount in tonnes and the willingness to pay. It may depend on the difficulties to refer the oil spill amount to the actual consequence. The mean value is therefore better understood as expressions of attitudes. The value is therefore interpreted as the willingness to pay for avoiding a “large oil spill” damaging the environment, which can be referred to consequence four and consequence five events. The total cost for an accident would therefore be multiplied with the consequence four and five failure fraction, see equation 28. A more detailed description of what consequence 4 and 5 means can be found in chapter 5.

(Equation 28) $Total_{NMV} = (FF_4 + FF_5) \cdot \overline{NMV}$

$FF_4$ = Failure fraction consequence 4 > 1000 tonnes
$FF_5$ = Failure fraction consequence 5 > 10 000 tonnes

**B.2.4 Market Costs – Ecosystem services**
Large oil spills leads to degradation of natural resources and their services in the aftermath of an incident. The pollution directly cause socio-economic damage and affects a variety of interest groups, especially at places where the ecosystem provides human population with plenty of benefits /37/. The seas for example often play an important role in both regional and national economy with many coastal communities depending on fishery and tourism income. A large scale oil release can lead to major monetary losses.

One way of predicting the socioeconomic damage is by using EPA BOSCEM, see equation 29, which was developed to provide the Environmental Protection Agency in United States a model for estimating actual and hypothetic oil spills. The model is taking impact to tourism, commercial fishing, private property and port closure into account. It is based on historical data, but unlike many other models it also incorporates specific spill factors such as spill amount, oil type and socioeconomic & cultural value /15/. Because of the scenario specific input the model is assumed to be more accurate than strictly generic values.

(Equation 29) $T_{SCC} = SC \cdot SCM \cdot SA \cdot CF$

$T_{SCC}$ = Total Socioeconomic cost [$]
SC = Per-tonne socioeconomic cost, Table 35
SCM = Socioeconomic cost modifier, Table 36
SA = Spill Amount, Equation 25
$CF$ = Currency factor

**Table 35 Per gallon base socioeconomic cost [SC] /15/.**

| [SC] | Socioeconomic Base Per-$m^3$ Costs [$/$m^3$] | | | |
|---|---|---|---|---|
| Volume [$m^3$] | Volatile Distillates[1] | Light Fuels[2] | Heavy Oils[3] | Crudes[4] |
| <2 | 17 100 | 21 100 | 39 600 | 13 200 |
| 2-4 | 70 000 | 87 200 | 158 500 | 52 800 |
| 4-40 | 105 700 | 132 100 | 237 800 | 79 300 |
| 40-400 | 47 600 | 52 800 | 132 100 | 37 000 |
| 400-4000 | 23 800 | 26 400 | 52 800 | 18 500 |
| >4000 | 18 500 | 23 800 | 46 200 | 15 900 |

[1]Including Gasoline, jet fuel, kerosene
[2]Light fuels, light crude, light oils
[3]Heavy oils, Heavy Crude, Lube oil, Tars
[4]Crude, not specifically identified heavy or light crudes, intermediate fuel oils, mineral oils

**Table 36 Socioeconomic cost modifier [SCM] /15/.**

| Spill Impact Sites | Examples | Socioeconomic Cost modifier |
|---|---|---|
| Predominated by areas with high socioeconomic value that may potentially experience a large degree of long-term2 impact if oiled. | Subsistence/ commercial fishing, aquaculture areas | 2.0 |
| Predominated by areas with high socioeconomic value that may potentially experience some long-term2 impact if oiled. | National park/reserves for ecotourism/nature viewing; historic areas | 1,7 |
| Predominated by areas with medium socioeconomic value that may potentially experience some long-term2 impact if oiled. | Recreational areas, sport fishing, farm/ranchland | 1.0 |
| Predominated by areas with medium socioeconomic value that may potentially experience short-term2 impact if oiling occurs. | Residential areas; urban/suburban parks; roadsides | 0.7 |
| Predominated by areas with a small amount of socioeconomic value that may potentially experience short-term2 impact if oiled. | Light industrial areas; commercial zones; urban areas | 0.3 |
| Predominated by areas already moderately to highly polluted or contaminated or of little socioeconomic or cultural import that would experience little short- or long-term impact if oiled. | Heavy industrial areas; designated dump sites | 0.1 |

### B.2.5 Total environmental costs

The total environmental costs are simply the sum of market costs and non-market costs. It is explained by equation 30. For further details, see descriptions under respective headline. $T_{SCC}$ and $Total_{NMV}$ can be calculated by using equation 28 and equation 29.

(Equation 30) $TC_{Environment} = Total_{NMV} + T_{SCC}$

## B.3 Commercial Impact

When an accident occur it can lead to heavy commercial cost due to lost production, clean-up operation, asset losses, third party claims, damaged trademark, price fall on stock market etcetera. In this thesis the commercial costs are limited to cover the physical events, such as operational cost for handling the situation and loss of production. However, costs such as third party claim are also taken into consideration as they are often based on socio-economic costs and environmental damage.

### B.3.1 Loss of production

An offshore oil well can produce in range less than 100 to several thousand barrels per day /8/. There is multiple oil types on the world market, but two of the most heavily traded are the WTI-oil from the Mexican Gulf and Brent-oil from North Sea. The oil price per barrel changes over time, as seen in Figure 37. In 2012 the average price for one barrel of Brent-oil was $111.67 per barrel while WTI-oil had an average of $94.05 per barrel /11/.

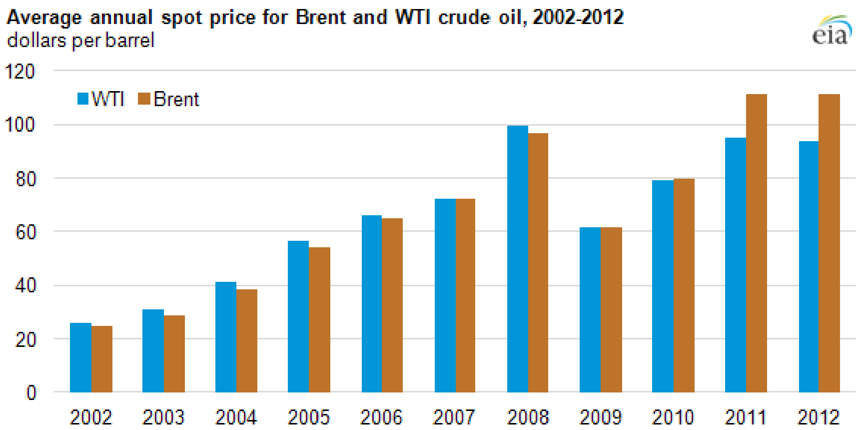


**Figure 37 The world market price of oil /11/.**

It is impossible to predict the future oil price. However, historical data can be used to make proper estimates. Earning per day, EPD, and production cost per day, PC, is site specific values. The total production loss in monetary terms can be calculated by equation 31 and equation 32. $T_{mean}$ can be calculated by equation 33.

(Equation 31) $TPL = EPD \cdot T_{mean}$

(Equation 32) $EPD = P \cdot PB - PC$

(Equation 33)

$$T_{mean} = \frac{F_{wellhead\ \&\ Xmas\ tree} \cdot T_{wellhead\ \&\ Xmas\ tree} + F_{manifold} \cdot T_{manifold} + F_{Pipeline} \cdot T_{Pipeline} + F_{Riser} \cdot T_{Riser}}{F_{subsea\ system}}$$

| | |
|---|---|
| TPL | = Total production loss |
| EPD | = Earning per day |
| $T_{mean}$ | = Average Number of Days without production |
| EPD | = Earning per day |
| P | = Production [barrels/day] |
| PB | = Price/Barrel |
| PC | = Production costs/day |

### B.3.2 Clean-up costs

Every oil spill is different from another and affected by multiple factors. Some of the most important are the type of oil, the location of the spill, the amount of oil spilled and management and quality of response operations /14/. The amount of oil matters because of its correlation to clean up efficiency while the oil recovery ratio increases significantly as spill size increases. That is explained by the fact that small spills are easier dispersed by wind and waves. Large spills are also cheaper on a per-unit basis because of the costs of mobilizing equipment, personal and bringing expertise for the response operation. However, very small spills less than 7 tonnes can be left for "natural cleaning" in hart weather making them free on a clean-up basis /16,37/.

The success of a clean-up operation also depends on the features of the oil released. Lighter fuel usually has high toxicity, but they are also volatile and most of it evaporates or dissolves before any of the products can be removed. In these situations the response operations usually focus on preventing flammable hazards. Heavy fuel on the other hand is much more persistent and needs more sophisticated and expensive clean up strategies, such as mechanical or manual recovery /16/.

Finally, the location of the oil spill is important due to the increased cost of near shore releases. That is mostly explained due to higher probability of shoreline impact. Research made by Etkin (2000) shows that near shore oil spills are almost three times as expensive as offshore oil spills. Furthermore, the knowledge and chosen combat strategy are crucial in order to protect sensitive coast regions both on and off shore. An estimation of how well different regions cope with oil spills are provided by /32/.

A model of predicting future costs of oil spills is provided by 20. The model is built on analyses of historical spill cost data taking quantity, oil density and level of preparedness in consideration. It resulted in a linear regression with the factors as independent variables. Even distance to shore and cloudiness were investigated, but somewhat surprisingly it led to reduced accuracy in terms of $R^2$, which is a measurement of how much the total variability from the true results reduces or increases when a variable is added. The reduced formula, with three instead of five variables also has the advantage of being almost completely independent of location, except the differences between regions as shown in Table 37. Therefore, the reduced variable set will be used due to better accuracy in terms of $R^2$ and more user-friendliness. $R^2$ is the coefficient of determination which measure how much of the variation is explained by the linear relationship.

The study finally came up with two models, one total cost model and one cost per tonne model. An inspection showed that they have different regions of optimal performance, where the cost model performed best in the middle range and the cost per tonne model everywhere else. The best accuracy is occurred when using both formulas are used based on the cost interval $[4 \cdot 10^6 - 4 \cdot 10^7]$. If both predictions should end up within the interval, the cost model should be chosen, se equation 34. On the other hand, if both predictions end up outside the interval the per tonne model, equation 35, should be chosen. If one prediction are inside the interval and one prediction outside, equation 35 (per tonne model) which has better average estimates could be chosen or the equation giving the highest value. The average spill amount can be calculated by the equation presented in section A.1.1.

Interval: $[4 \cdot 10^6 - 4 \cdot 10^7]$

(Equation 34 – Cost model)

$$\text{Spill cost [\$]} = 156\,5934 \cdot (\text{Spill amount [Tonnes]}) + 56\,781\,000 \cdot \left(\text{Oil density } \left[\text{kg/dm}^3\right]\right) + 2\,303\,500 \cdot (\text{Level of preparedness}) - 49\,979\,000$$

(Equation 35 – per tonne model)

$$\text{Spill cost [\$]} = \left(29\,471 \cdot \left(\text{Oil density}\left[\text{kg/dm}^3\right]\right) + 863\,0906 \cdot (\text{Level of preparedness}) - 24\,060\right) \cdot (\text{Spill amount [Tonnes]})$$

**Table 37 Regional level of preparedness /32/.**

| Regional Sea | Level of Preparedness | Regional Sea | Level of Preparedness |
|---|---|---|---|
| North-east Pacific | 1 | Caspian | 1 |
| South-east Pacific | 1 | Baltic | 3 |
| Upper South-west Atlantic | 2 | North-east Atlantic | 3 |
| Wider Caribbean | 1 | South Asian Seas | 1 |
| West & Central Africa | 1 | East Asian Seas | 2 |
| Eastern Africa | 1 | South Pacific | 1 |
| Red Sea & Gulf of Aden | 1 | North-west Pacific | 2 |
| Gulf Area | 1 | Arctic | 2 |
| Mediterranean | 2 | Antarctic | 1 |
| Black Sea | 1 | | |

The clean-up cost result can be applied to other nations by using the correction factor for specific nations/regions presented in Table 38 and equation 36. The Table is based on the average per-unit marine oil spill clean-up costs presented in 75. Since the model is based on united state conditions it is set to the nominal value of 1. The high spiller liability, clean up standards and labour costs contribute to the high clean-up costs in United States. However, it should be mentioned that some of the correction factors are based on relatively small number of spills and therefore have a greater amount of uncertainty.

**Table 38 Correction factors for nation/region clean-up costs /16/**

| Country | National-Regional Correction Factor |
|---|---|
| United States | 1 |
| Norway | 0,90 |
| Denmark | 0,44 |
| Australia | 0,23 |
| Brazil | 0,22 |
| UK | 0,12 |
| Israel | 0,09 |
| United Arab Emirates | 0,03 |
| Average Africa | 0,12 |
| Average Asia | 1,07 |

(Equation 36) Total clean-up costs = Spill costs [$] $\cdot$N-$R_{correction}$ $\cdot$ CF $\cdot$ IF

Spill costs [$]= Clean-up costs according to equation 34 or 35 [$]
N-$R_{correction}$ = National/Regional Correction Factor, Table 38
CF = Currency factor
IF = Inflation factor, start from 2007

### B.3.3 Total commercial impact

The total commercial impact costs are the sum of the loss of production costs and clean-up costs. It is explained by equation 37. For further details, see descriptions under respective headline.

(Equation 37) $TC_{Comercial}$ = TPL + Total clean-up costs
$TC_{Comercial}$ = Total commercial cost
TPL = Total production loss

**B.4 Safety Impact**
The purpose of putting monetary values on human lives is to set up evaluation criteria's which can be used to assess the acceptable or tolerable risk. The monetary term is called value of statistical life, VSL, and is roughly the collective willingness to pay for saving one life. Some people may think that it is unethical to put a value of human lives, but the truth is that it is done all the time in several sectors, such as medical care and traffic safety. All sectors which include risk have to balance the need of safety measures against the actions benefit. If the value of a human life is set to infinite, then it would not be possible to e.g. drive cars thus it always involves a slight probability of dying. There are always a "trade-offs" and people are not ready to forget all their benefits for less risk of dying.

It is also important to understand that the VSL always refers to hypothetical lives used for estimating the good out of different safety measures. It is just a tool. If real people are stuck at a burning topside facility, then they are not statistical lives anymore and a rescue operation can be allowed to be much more costly.

The VSL is not true science and can be questioned. Values differ between different sectors and countries since it depends on peoples risk perception. For example, a life in air traffic is more worth than a life in car traffic according to safety investments. Some factors affecting peoples risk perception are listed below /12,40/.

- Who is exposed?
- Who gains the benefits?
- Is the risk controllable or not?
- Is the risk perceived as natural?
- How big are the consequences?

It is important to not just transfer a VSL to a completely different situation. However, the shipping industry has similar conditions due to the factors listed above. The shipping industry has put a value of fatality to three million (2006 $) /29/. The British Health and Safety Commission think in a similar way when they recommend a value more than one million (2001 £) /24/.

According to the statement above, the VSL in this thesis is set to four million (2013 $). It is higher than suggested by IMO (2004), but on the other hand it is not an unusual value compared to several local government decisions. Only one value is set and no correction of it is made due to geographical location of the Subsea system. The oil companies are often operating international and their ability to pay are not affected by national borders. The fatalities expressed in monetary terms are therefore as shown in equation 38. For taking time into account the equation is multiplied by the inflation factor. The inflation can be assumed to be 3 % each year after 2013 if no other data is available.

(Equation 38) $TL_{Fatilities} = VSL \cdot CF \cdot X \cdot IF$

$TC_{Fatilities}$ = Total value of statistical lives [$]
VSL = Value of Statistical Life [4 million $]
CF = currency factor
X = Number of life threatened
IF = Inflation factor, start from 2014

### B.5 Cost-Benefit Analysis

CBA compares the savings of an avoided hazard versus the cost of the risk reducing measures. If more than one potential IPL is identified, the method can be used to choose the most cost effective one /6/. An advantage with CBA is that all risks, safety, environmental and commercial, is measured in monetary terms and can be summarized into a single risk. In other words, an advantage of the model is that it takes the whole risk picture into account.

According to cost-benefit theory, a preventive action shall be implemented as long as the benefit of the action exceeds its cost. The benefit can be measured by calculating the differential cost between the average yearly cost with and without additional protection layer, as described in equation 39.

(Equation 39) $C_{AA} < AP \cdot \text{Benefit}$

| | |
|---|---|
| $C_{AA}$ | = Cost of averting a spill [$] |
| AP | = Assurance parameter [AP=1.6] |
| Benefit | = Benefit out of additional safety measures [$] |

The cost of additional safety measures ($C_{AA}$) depends on the IPL cost during its full lifecycle of operation. A higher SIL will result in additional costs, such as increased inspection and maintenance requirements. During some maintenance operations, the oil production may have to be completely shut down. $C_{AA}$ can be calculated by using equation 40.

(Equation 40) $C_{AA}$ = (Inspection & maintenance cost) + (additional equipment costs) + (average loss of production during maintenance/inspection operations)

The assurance parameter (AP) is reflecting the fact that it is better to spend resources on preventing a disaster rather than lose money on an actual hydrocarbon release. AP shall be decided by the LOPA expert group, but is always greater than 1. There is no standard recommendation for the assurance factor value, but corresponding to implemented OPA 90-rules, an American Oil Pollution regulation, the AP factors was found to be 1.6 as an average /14/. The recommendation is therefore, according to the OPA 90 decision that AP is set to 1.6.

The benefit out of the safety measures (Benefit) is a combination of the cost of a hazard (TC) and the reduced frequency of these hazards to occur due to added protection layers ($\Delta F$). The cost of an occurred spill depends on several factors, such as commercial losses, environmental damage and the number of fatalities. Models for calculating these factors are presented in the beginning of this appendix. The overall benefits can be calculated by using equation 41.

(Equation 41) $\text{Benefit} = \Delta F \cdot TC = (F_{\text{without PLs}} - F_{\text{with PLs}}) \cdot (TC_{\text{Environment}} + TC_{\text{Commercial}} + TC_{\text{Fatalities}})$

| | |
|---|---|
| $F_{\text{without PLs}}$ | = Subsea system leakage frequency |
| $F_{\text{with PLs}}$ | = Leakage frequency when additional protection layers has been added |
| $TC_{\text{Environment}}$ | = Total environmental cost, according to appendix B.2.5 |
| $TC_{\text{Commercial}}$ | = Total commercial cost, according to appendix B3.3 |
| $TC_{\text{Fatalities}}$ | = Total safety cost, according to appendix B4 |

The CBA can be used in order to determine appropriate SIL for SIFs. However, it shall not be used as the main SIL-determination model. It is highly recommended that the result is only used in order to recommend a higher SIL than what is suggested by using the LOPA-model. That is also why this CBA is placed here in appendix B and not as a part of the main paper.

# Appendix C - Offshore platforms

Depending on water depth and size of the installation, there are several structures for offshore oil production which allows crew to perform tasks to support the production. The structures have their various benefits and drawbacks, some of them are floating facilities moored to the sea bed and other are structures attached into the seabed. The facilities usually includes production separators, water and gas separators, pipelines, pumping stations, compressors, water treatment installations, oil and gas storages, accommodation quarters etcetera /8/. The most common platform types are described below and are visualised in figure 12.

*Shallow water complex*
The platform complex consists of several different platforms connected with gangway bridges. The individual platforms have different functions and are described as Wellhead Platform, Riser Platform, Processing Platform, Accommodation Platform and Power Generation Platform. They typically operate at water depth about 100 metres /8/.

*Gravity Base Platform*
Gravity base platform are fixed bottom structures made of concrete. They are heavy and do not need any supporting piles. The gravity base platform typically operates in 100-500 metres water depth /8/.

*Compliant Tower*
The compliant tower consists of a narrow tower attached to the sea floor. The tower has flexible legs which make them withstand significant lateral forces. A compliant tower can operate at water depth up to 500-1000 metres /8,3/.

*Tension leg platform (TLPs)*
TLPs are floating platforms held in place by vertical tendons connected to the seabed in a manner that limit the vertical movement. The tendons are made of hallow tensile steel pipes. The TLP are usually used in deep water up to 2000 metres. Mini-TLPs can also be used as utility, satellite or early production platforms for larger deep water discoveries /3/.

*Floating production systems (FPS)*
A FPS is typically a tanker which can rotate freely around pointing into wind and wave direction. The FPS has wire rope or chain connections to several anchors and can also be dynamically positioned using thrusters. The variant is common with subsea wells and can be of service at water depth up to 2000 meters /8/.

*Spar platforms*
The Spar can be designed in three different ways. The conventional design has a single floating cylinder hull while the truss spar has a midsection of truss elements connected to an upper buoyant hull and a lower tank of ballast. It can also be constructed as a cell spar which is built of multiple cylinders. Spars are moored to the sea bed with conventional mooring lines /3/. The spars can be on service on depth up to 3000 metres and is often coupled to subsea wells.

*Semi-submersible platforms*
Semi-submersible platforms have hulls and buoyancy enough to float but of weight to keep it upright. The semi-submersibles are capable of operating at water depth more than 3000 metres /3/. The platform stays in place by use of a dynamic positioning system or a pre laid mooring system /39/.

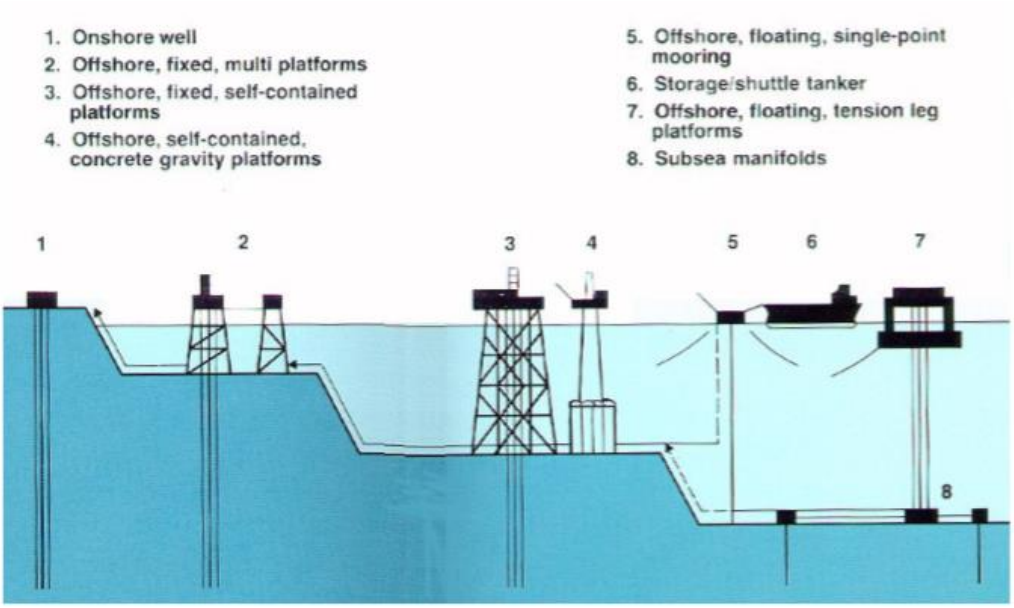


**Figure 38 shows some of the most common oil and gas production facilities /8/.**

## Appendix D- HAZOP

This section includes a summary of two subsea system HAZOPs. Only those parts assumed to cause environmental or safety consequences have been included. The HAZOPs have been studied during the risk- and initiating cause identification process as two sources among several. The reports were provided by Oilconx Risk Solution.

| **XXX** | | | | |
|---|---|---|---|---|
| **No.1 Production line from well to manifold** | | | **Pressure** | |
| Guideword | Cause | Consequence | Safeguards/Actions | Comment |
| Less (1.4) | Insufficient sealing of connectors or rupture of piping. | HC release to environment. | Connectors Pipings Detectors | (Leak detectors) |
| Less/No (1.5) | Insufficient sealing of wedge connector after installation. | Seawater ingress into the production system results in increased risk for hydrate formation, ice formation and corrosion. | - | (Detection of sea water ingress is detectable in the test separator) |
| Less/No (1.6) | During shutdown periods, the system will have a pressure below the hydrostatic pressure, which will give an increased risk for sea water ingress at all possible leak points. | Seawater ingress leads to an increased risk for corrosion and hydrate/ice formation during start-up. | | Evaluate the material selection to ensure that the SPS tolerates seawater ingress |
| | | | | |
| | | | **Erosion** | |
| Guideword | Cause | Consequence | Safeguards/Actions | Comment |
| (1.16) | The Erosion Probe (EP) is located upstream the choke valve. The flow rate is higher downstream the choke, and thus also the potential for erosion. | Suboptimal location of the EP. Damages due to erosion may not be detected. | Communicate the limitations of the material selection regarding H2S and mercury content in the well stream. | |
| | | | **Piping/Material** | |
| Guideword | Cause | Consequence | Safeguards/Actions | Comment |

| | | | | |
|---|---|---|---|---|
| | H2S and mercury in the well stream. | Degradation of piping/equipment | | |
| | | | **Temperature** | |
| Guideword | Cause | Consequence | Safeguards/Actions | Comment |
| Less (1.12) | Suboptimal position of the PCV during start-up may give a too large temperature drop downstream the PCV due to Joule- Thompson effect. | If low temperature downstream PCV during start-up exceeds design temperature limitations, there is a potential for material degradation. Start-up procedures | Start-up procedures | There shall be start- up procedures in place to avoid temperatures below - 29°C. Temperature control is performed by choke adjustment and MEG injection |
| **No.2 Annulus line from well to HCM (Meg/serviceline)** | | | **Temperature** | |
| Guideword | Cause | Consequence | Safeguards/Actions | Comment |
| More (2.5) | Depressurization of production gas into the MEG/Service line giving high flow rates | Too fast depressurization of the annulus/production could cause the umbilical to be subjected to temperatures above its design temperature. Possible material l degradation if it occurs over a sufficient time. | | |
| **No.13 Field layout** | | | **Temperature** | |
| Guideword | Cause | Consequence | Safeguards/Actions | Comment |
| Less/No (13.2) | Leakages from the flowline system, e.g. downstream PWV for any well at AHA SPS. | Depressurizaton of HC content to sea and sea water ingress into the SPS system. As the manifold valves are ROV operated only, segregation by leakages is not possible. | | The potential leakage scenarios were also included in the risk analysis, according to information provided by Statoil |

| YYY | | | | |
|---|---|---|---|---|
| **Production line from well to MPVs** | | | **Pressure** | |
| Guideword | Cause | Consequence | Safeguards/Actions | Comment |
| More (1.2) | Unintentionally closed manifold branch valves during normal operation and simultaneous scale injection. | Potential for overpressure in the main production line if the volume of scale inhibitor is sufficient. | Ensure that the topside pressure protection of the scale inhibitor injection system is aligned with the limitations of the subsea design pressure. | Ensure that the topside pressure protection of the scale inhibitor injection system is aligned with the limitations of the subsea design pressure. |
| Less/No (1.4) | There is a potential for leakages from any of the connectors (e.g. FCM hub or HCS) due to insufficient sealing. | Unable to detect minor leaks due to no leakage detection systems (Acoustic or HCLD) | | Large leakages is assumed detected by pressure readings from PTs. |
| | | | **Temperature** | |
| Guideword | Cause | Consequence | Safeguards/Actions | Comment |
| Less (1.11) | During start-up, the temperature can drop down to -31 C downstream the choke if the start-up procedures are not executed properly | Material degradation and increased likelihood for hydrate plug formation. | | Evaluate the effects of low temperature for the isolation valves FSV1 and FSV2. Evaluate the location accordingly |
| Less (1.12) | Stagnant conditions and cool down following an unplanned or planned shutdown. The no touch time is defined as 4 hours. If some of the stagnant lines are not preserved within 4 hours, the temperature may drop below HET | Potential for hydrate formation. | Check the valve manipulation procedure to ensure that the flushing can be completed within 4 hours after the no touch time of 4 hour | Jumpers and X-mas tree shall be flushed with methanol after a shutdown. Cool down time is expected to be in the order of 8 hours No formations of stagnant fluids are expected during normal |

| | | | | |
|---|---|---|---|---|
| | | | | operation, i.e. no dead legs. |
| | | | **Flow** | |
| Guideword | Cause | Consequence | Safeguards/Actions | Comment |
| Less/no (1.7) | No flow due to hydrate formation Hydrate formation may occur by human error during start-up or failure by the methanol distribution system. | Blockage in the production line, pressure build up (still within the design premises) | Depressurization of the main line / injection of methanol will be applied as means to remove the hydrate plug Depressurization to the sea has been mentioned as a possible option<br><br>Ensure that a contingency plan is in place to remove hydrate plugs from the wells, XMT segment and the main production line | According to HAZOP discussions, the most challenging place for removal of hydrate plugs is in the XMTs |
| | | | **Erosion** | |
| Guideword | Cause | Consequence | Safeguards/Actions | Comment |
| (1.15) | It was discussed whether the acoustic sand detector is located at the optimal location in order to detect sand and thus the potential for erosion. Possible suboptimal design | Increased risk for a sand content higher than expected not being detected. Thus, there is an increased potential for erosion. Sand screens | Check the location of acoustic sand detectors | The wall thickness monitoring is located where highest erosion is expected, meaning downstream the choke with bend and highest velocities. |
| (1.16) | The wall thickness monitoring system introduces a cold spot where the steel is exposed. | Mechanical damage/ hydrate formation | Evaluate the thermal design for the access point for wall thickness monitoring | |
| | | | **Corrosion** | |
| Guideword | Cause | Consequence | Safeguards/Actions | Comment |
| (1.20) | Water ingress through sample points or other connection points due to the hydrostatic pressure | Increased risk for corrosion | Corrosion inhibitor mainly for downstream segment - not for the X-mas tree | Material class in the tree and the sample points is HH. This is for the production side. For the annulus side |

| | | | | |
|---|---|---|---|---|
| | | | | the material class is EE |
| (1.21) | The chemical compatibility study is not finalized. Thus, there is an increased risk for incompatibility between the chemicals applied and the material selection. | Possible corrosion and material degradation. | Ensure that fluid compatibility study is carried out at detail level. | A compatibility assessment has been performed for the chemicals which are planned to be used. This is at system level. More detailed study is required. |
| **Chemical injection lines from manifold connector to injection points** | | | **Pressure** | |
| Less/No (3.2) | Leakages between CITVs and injection valves, e.g. from CITVs poppets. | Leakage of hydraulics to the environment and loss of chemical injection with increased risk for corrosion (by loss of corrosion inhibitor).<br><br>Unable to detect leakage, which may give a longer duration of the leakage. | | It is uncertain whether this type of minor leakages may be detected at all. |
| **Chemical injection from FPU to injection points at 4-slot production manifold** | | | **Pressure** | |
| Guideword | Cause | Consequence | Safeguards/Actions | Comment |
| More (5.1) | During pre-commissioning, chemicals are injected into the manifold system, but there is no control of the injection pressure. | During pre-commissioning possible over pressurization of the manifolds from small bore-lines. | Ensure that over pressurization hazard during pre-commissioning is addressed as a part of pre-commissioning work.<br>Check that the precommissioning procedure covers the means to avoid this hazard | No pressure monitoring is in place during pre-commissioning |