RECOMMENDED FAILURE RATES FOR PIPELINES

Recommended failure rates for pipelines

Equinor Energy AS

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Objective:

On behalf of Equinor, DNV has updated the previous issue of the report "Recommended Failure Rates for Pipelines". The report presents several sources of pipeline failure data. The objective of this report is to provide failure frequencies for Offshore and onshore flexible and steel pipelines transporting HC oil, gas, H_2 and CO_2.

The frequencies are to be used in risk assessments, availability analysis and contingency planning.

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1 Executive summary

1.1 Introduction

On behalf of Equinor Energy AS, DNV has revised the previous version of the report (Recommended failure rates for pipelines, ref. /1/). The report presents several different sources for pipeline failure data and models for estimation of failure frequencies for offshore and onshore pipelines, risers, jumpers, and other equipment attached to pipeline systems.

Compared to the previous revision issued in 2017, the underlying statistical material has been updated and the failure data updated accordingly. The scope of work for this report edition is extended compared with the scope for previous editions, with the main changes presented in chapter 1.3.

The main objective of this document is to:

- Present knowledge and understanding of failure mechanisms, causes, and factors influencing failure scenarios associated with pipeline systems;
- Provide generic recommended failure rates for pipelines (offshore and onshore), risers, jumpers, subsea equipment and isolation joints; and
- Provide models to enable analysis of individual pipelines based on exposure and conditions which are likely to be pipeline specific ("score grade model", dragged anchor, ship foundering).

Failure frequencies and failure frequency models are provided for:

- Offshore oil and gas pipelines; both steel and flexible pipelines;
- Onshore oil and gas pipelines; steel pipelines;
- Risers; both steel and flexible risers;
- H_2 and CO_2 pipelines onshore and offshore;
- Offshore equipment included in pipeline systems; and
- Isolation joints.

The frequencies may be applied in quantitative risk assessments (e.g. pipeline QRAs/TRAs), availability analyses and contingency analyses. It should be acknowledged that the failure frequencies are produced based on pipeline populations with a wide variety of features. For more detailed failure frequencies for a specific type of pipeline, and/or associated with specific failure modes and mechanisms, it is recommended to do more in-depth assessments of the relevant specific features.

The chapter describing failure mechanisms, causes, and influencing factors has been revised based on a review of various pipeline failure data sources and scientific articles, and through discussions with pipeline technology and pipeline operations experts.

Recommended failure frequencies for pipelines transporting hydrocarbons have been revised mainly based on new data sources including PARLOC 2020 (ref. /3/), CONCAWE (ref. /16/), offshore pipeline failure data for the NCS provided by Havtil (ref. /13/ and ref. /14/), and onshore pipeline failure data provided by Equinor (ref. /30/). Revised failure frequencies are presented for subsea equipment based on OREDA (ref. /27/) and PLOFAM (ref. /28/).

Failure frequencies for pipelines transporting CO_2 have been recommended based on PHMSA data compiled by Vitaly et.al. (ref. /20/). The presence of impurities and humidity is an important topic of concern with regards to internal corrosion in CO_2 pipelines (ref. /24/ and ref. /25/). However, if the selected product specification is sufficiently qualified for the pipeline materials, it is foreseen that internal corrosion can be managed to a level comparable to current industry experience for CO_2 pipelines.

Failure frequencies for pipelines transporting H_2 have been recommended. The failure data identified for H_2 pipelines are however judged insufficient for establishing failure frequencies. Failure frequencies for H_2 pipelines are thus based on failure frequencies for HC pipelines and qualitative assessments.

The approach used to calculate failure frequencies for a pipeline system involves the five main steps presented in Figure 1-1. The first step in the approach is to divide the pipeline into different segments in order to apply appropriate failure frequency models to the different parts of the pipeline. The relevant pipeline segments are shown in Figure 1-2.

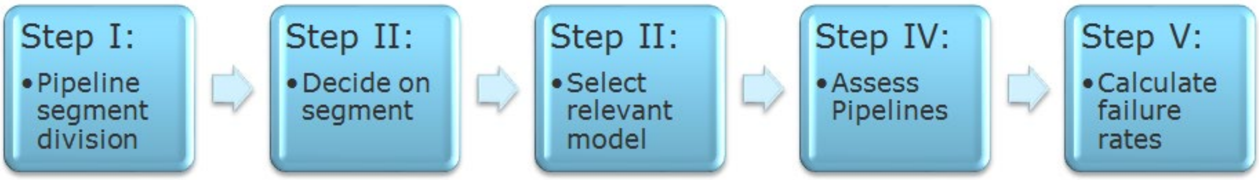

Figure 1-1 Approach used to calculate pipeline system failure frequency

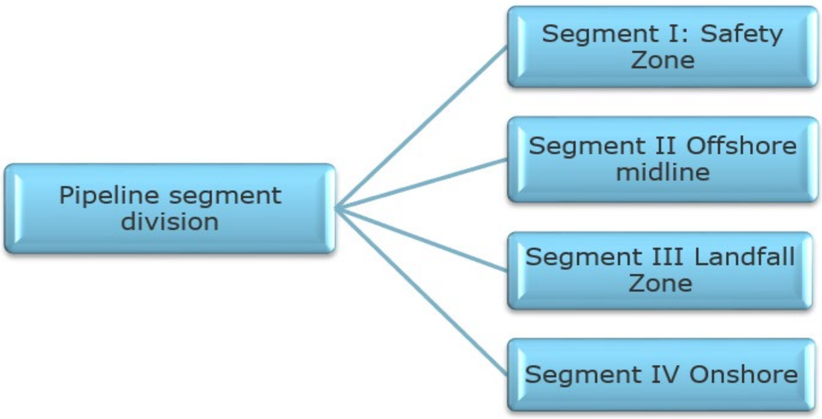

Figure 1-2 Pipeline segments

After dividing the pipeline into segments, each individual segment needs to be assessed with the failure frequency model relevant for this segment and transported product. The relevant models and failure frequencies are selected from the alternatives which are presented in chapter 5. Failure frequencies used in the failure frequency models are presented in chapter 1.2.

The failure frequency contribution on the midline section of offshore pipelines is dependent on various characteristics, including length independent characteristics. A specific model to assess the relevance, and the exposure, of a set of characteristics is developed and described in chapter 5.3.4. To evaluate the effect of these (e.g. to assess the loads and impacts a specific pipeline might be exposed to), the participation of pipeline expertise is necessary.

1.2 Recommended failure frequencies

Table 1-1 presents the recommended failure frequencies established in this study. Recommended distributions for hole sizes from offshore risers and pipelines are given in Table 1-2, while recommended distributions of riser leaks per riser section are given in Table 1-3. Recommended distributions for hole sizes from onshore pipelines is given in Table 1-4.

The recommended failure frequencies are applicable for normal operations. Thus, e.g. construction and testing phases are not represented by the recommended failure frequencies, and risk related to such phases must be evaluated separately.

The recommended failure frequencies are based on historical data obtained for pipelines assessed representative and within the inclusion criteria assessed relevant for the different pipelines categories. The failure frequencies recommended for certain pipeline categories will thus span pipeline populations across regions and various other aspects, while there is an uncertainty associated with how the failure frequency across such aspects may deviate. It is acknowledged that a more refined categorisation of pipelines with respect to pipeline material, fluid type, and other aspects would be appreciated. The level of detail and refinement of categories must however also consider the amount of failure data and pipeline populations available. With more refined categories, the failure and population data per category will be further reduced and the corresponding uncertainty in the estimates will increase.

Table 1-1 Recommended failure frequencies

Pipeline	Description	Failure frequency	Unit	Reference
Offshore pipelines Outside safety zone	Steel: Well stream pipelines containing unprocessed fluid. [1,2] *(Model alternative 3 is presented here)*	4.3 E-04 2.2 E-04	km year (0-10 km) km year (> 10 km)	/3/, /13/, /14/
	Steel: Processed oil, gas with pipeline diameter ≤ 24”. [3,4]	1.9 E-05 5.5 E-05	km year score grade-year	
	Steel: Processed oil, gas with pipeline diameter > 24”. [3,4]	3.5 E-06 1.3 E-04	km year score grade-year	
	Flexible pipelines	1.0 E-03	km year	
	Failure frequency from inadvertent dragging of anchors by ships under way	Pipe specific (see Appendix C)		
Offshore pipelines inside safety zone	Steel pipelines	4.0 E-04	year	/3/, /13/, /14/
	Flexible pipelines	6.0 E-04	year	
	In order to perform a correct failure frequency assessment for a subsea pipeline, the failure frequency related to external loads in the platform zone as a result of dropped objects should be added to the failure frequency.			
Risers	Flexible risers	2.1 E-03	riser year	/3/, /13/, /14/
	Steel risers ≤ 16”	8.2 E-04	riser year	
	Steel risers > 16”	1.1 E-04	riser year	
Jumpers	All jumpers	4.7 E-03	jumper year	/3/, /13/, /14/

1 For offshore steel pipelines transporting unprocessed HC there are three model alternatives. Here the parameters applicable for model alternative 3 are presented. This is the recommended model alternative and applies two separate failure frequencies measured per pipeline-km-year. This alternative reflects that the failure frequency measured per pipeline-km-year is reduced after a certain distance (where 10 km is recommended to be applied). For pipelines with a length less than 10 km only the first failure frequency value should be applied. For pipelines with a length exceeding 10 km, the contribution from the exceeding pipeline length is recommended to be modelled using the second failure frequency value. All three model alternatives are presented and discussed in section 5.2.4.4.

2 The failure frequency for well stream pipelines and other pipelines containing unprocessed fluid is merely an indicator and should be used with caution. Amongst the pipelines there is extensive variation within choice of materials, composition of oil and gas, temperature and other operational conditions.

3 For offshore steel pipelines transporting processed HC, both a length dependant and a length independent failure frequency should be established. The length dependent frequency is based on pipeline km-years. The length-independent contribution shall be established applying a score grade model (ref. chapter 5.2.6)

4 Score-grade year refers to the factor that should be multiplied with a score grade value (ref. score grade model presented in 5.2.6) obtained for the pipeline to establish an annual length independent failure frequency.

Table 1-1 continued

Pipeline	Description	Failure frequency	Unit	Reference
Landfall zone	Unless more specific data is available onshore data are recommended to be used for the landfall Zone.			
HC Oil pipelines onshore	Diameter: < 8”	4.5 E-04	km year	/16/
	Diameter: 8”-14”	2.0 E-04	km year	
	Diameter: 16”-22”	1.6 E-04	km year	
	Diameter: 24”-28”	1.2 E-04	km year	
	Diameter: ≥ 30”	1.6 E-04	km year	
HC Gas pipelines onshore Alt.1 [5]	Wall thickness: ≤ 5 mm	2.2 E-04	km year	/30/
	Wall thickness: 5-10 mm	1.0 E-04	km year	
	Wall thickness: 10-15 mm	1.1 E-05	km year	
	Wall thickness: > 15 mm	1.0 E-05	km year	
HC Gas pipelines onshore Alt. 2	Pipe diameter: ≤ 4 “	2.9 E-04	km year	/30/
	Pipe diameter: 6-10”	1.8 E-04	km year	
	Pipe diameter: 12-16”	1.2 E-04	km year	
	Pipe diameter: 18-22”	6.0 E-05	km year	
	Pipe diameter: 24-28”	3.3 E-05	km year	
	Pipe diameter: 30-34”	2.7 E-05	km year	
	Pipe diameter: ≥ 36	1.0 E-05	km year	
Subsea equipment	See chapter 5.2.7			/27/, /28/
CO_2 pipelines onshore	Wall thickness: ≤ 5 mm	4.2 E-04	km year	/20/
	Wall thickness: 5-10 mm	1.9 E-04	km year	
	Wall thickness: 10-15 mm	2.1 E-05	km year	
	Wall thickness: > 15 mm	1.9 E-05	km year	
CO_2 pipelines offshore	Pipeline diameter ≤ 24”	7.2 E-05	km year	
	Pipeline diameter > 24”	1.3 E-05	km year	
H_2 pipelines onshore	Wall thickness: ≤ 5 mm	2.7 E-04	km year	
	Wall thickness: 5-10 mm	1.2 E-04	km year	
	Wall thickness: 10-15 mm	1.3 E-05	km year	
	Wall thickness: > 15 mm	1.2 E-05	km year	
H_2 pipelines offshore	Pipeline diameter ≤ 24”	4.6 E-05	km year	
	Pipeline diameter > 24”	8.3 E-04	km year	

5 Frequencies for onshore gas pipelines have been provided both for pipe diameter and wall thicknesses.

For offshore risers and pipelines, the following guidance applies:

- The failure frequencies are additive such that the failure frequencies for risers, jumpers, pipelines inside the safety zone, and pipelines outside the safety zone, should be added to get the resulting failure frequency for a complete pipeline system.
- The failure frequency from topside ESD valve is not included in the riser failure frequency. This shall be based on topside process statistics and added to the calculated riser failure frequency.
- Failures recorded to be directly associated with valves, flanges, pig traps, isolation joints, and other equipment are not represented by the recommended failure frequencies for pipelines and risers. The failure frequency associated with such equipment must be added. It should however be noted that a flange between a riser and a pipeline / jumper is included.
- External loads causing damage to a pipeline, riser, or other HC equipment, inside the platform safety zone (i.e. a 500m zone surrounding the facility) have been removed from the list of failures used to establish the recommended failure frequencies. The frequencies for failures caused by e.g. dropped objects both from lifting operations, dropped / dragged anchor, and ship foundering must therefore be added separately[6].
- For risers guided through J-tubes or I-tubes, a separate assessment must be made to decide the most likely leak location(s), e.g. leaks through to top sealing or through the bell mouth.

Table 1-2 Recommended hole size distribution for offshore risers and pipelines

Category	Hole size range [mm]	Representative Hole size [mm]	Flexible risers and pipelines	Steel risers and pipelines	Jumpers
I	< 2	1	60 %	40 %	40 %
II	2 – 7	5	15 %	20 %	10 %
III	7 – 30	20	15 %	20 %	10 %
IV	30 – 80	50	5 %	10 %	15 %
V	> 80	Pipe diameter	5 %	10 %	25 %

Table 1-3 Recommended distribution of riser leak locations per riser section

Leak location	Steel risers	Flexible risers
Above splash zone	35%	10%
Splash zone	35%	30%
Midway in water column	15%	30%
Subsea at Riser base	15%	30%
All sections	**100 %**	**100 %**

[6] Models for estimating pipeline failures from dragged anchors and ship foundering are included in Appendix C and Appendix D respectively

Table 1-4 Recommended hole size distributions for onshore pipelines, based on utilisation factor

Category	Hole size range [mm]	Representative hole size [mm]	Utilization ≤ 70 %	Utilization > 70 %
I	< 2	1	15 %	15 %
II	2 – 7	5	25 %	25 %
III	7 – 30	20	35 %	17.5 %
IV	30 – 80	50	10 %	5 %
V	> 80	Pipe diameter	15 %	37.5 %

1.3 Main changes from previous editions

This is an updated edition of the Recommended Failure Rates for Pipelines report issued in 2017 (ref./1/). The main changes since the previous edition are the updated data sources, presented in chapter 4, and the updated failure frequencies, reported in chapter 5. Since the 2017 edition, new versions of PARLOC, EGIG and CONCAWE together with updated data from failures on the NCS, and updated anchor loss statistics, have been available for this report.

PARLOC data and offshore pipeline data from the NCS have been an important source for this guideline. Failure frequencies for offshore pipelines and risers have thus been updated with respect to the new combined failure and exposure data sets for offshore risers and pipelines on NCS and UKCS (PARLOC).

There are 3 main changes to the presentation of offshore hydrocarbon failure frequency. Separate failure frequencies are recommended for jumpers and for pipelines inside the platform safety zone. The hole size distributions for offshore pipelines and risers do not distinguish between risers and pipelines, however they do distinguish between pipeline material (i.e. steel or flexible).

For offshore steel pipelines transporting processed hydrocarbons, the failure frequency is assessed to consists of one length dependant fraction and one length independent fraction. The length independent fraction is recommended to be established based on an assessment of pipeline specific characteristics. There is a separate model, referred to as a "*score grade model*", established for quantifying the length independent failure frequency fraction. The score grade model for offshore steel pipelines transporting processed hydrocarbons has been updated as part of this edition.

A new score grade model has also been developed for onshore steel pipelines for transportation of hydrocarbon gas. As for the offshore score grade model the onshore score grade model is also based on a set of characteristics, however a different set more relevant for onshore pipelines. The failure frequency contribution per characteristic is assessed to depend on pipe wall thickness, and the empirical frequencies for onshore HC gas pipelines are also established based on wall thickness categories. Onshore HC liquid pipelines are categorised based on pipeline diameter and not wall thickness, and thus the onshore score grade model is thus not directly transferable to onshore HC liquid pipelines.

Recommended failure frequencies for pipelines transporting H_2 have been introduced in this edition. The failure data identified for H_2 pipelines are however judged insufficient for establishing failure frequencies. Failure frequencies for H_2 pipelines are thus based on failure frequencies for HC pipelines adjusted by qualitative assessments.

In this edition an assessment of failure modes and a recommended failure frequency for isolation joints are introduced. Recommended failure frequencies for subsea equipment has been revised and updated in this edition.

1.4 Discussion

To establish pipeline event frequencies, it is important to have a most complete set of relevant historical incidents, as well as a complete set of exposure data for the area and the period covered by the scope of the analysis. When associating data with a set of pipeline categories, it is vital that the quality of information registered for each event and pipeline is sufficiently good to allocate an event or a pipeline to one of the defined categories.

The experience from this project is that it is a challenging and time-consuming task to retrieve a complete set of relevant data corresponding to the scope of the study. When searching for data, one challenge is to select inclusion/exclusion criteria suitable to identify relevant failures and at the same time exclude most of the irrelevant incidents stored in the same repository. Failure to retrieve and filter the relevant data affects the completeness of the data used in estimating the recommended frequencies.

For a large fraction of failures identified it is challenging to extract necessary information to associate the failure or the pipeline with one of the defined pipeline categories. Particularly when combining data from several data sources, this becomes challenging due to variations in the data registration format.

In addition to the challenges with categorization of incidents into defined pipeline categories, additional information such as hole size and leak locations is often limited. For the new datasets obtained and reviewed for the update of offshore risers and pipelines failure frequencies it has not been possible to retrieve necessary information to establish a hole size distribution. To establish hole size distributions for offshore pipelines it is necessary to rely on an additional data repository to retrieve the necessary pipeline information. Domain knowledge and a good overview of data repositories are thus considered a vital prerequisite to achieve a solid data basis for frequency estimates.

The failure frequencies for some of the pipeline categories are based on a low number of failures. In some cases, no failures are identified within the inclusion / exclusion criteria set established for a pipeline category. This may indicate that the likelihood for failure within this category is low, particularly if the corresponding exposure data is substantial.

In some of cases failure rates for a category may be established through qualitative assessments of similarities and differences to other categories combined with knowledge of relevant pipeline failure characteristics; through a statistical approach considering that zero recorded failures can be represented by the expected value from a Poisson distribution assuming a 50 % probability of no occurrences; or it may be reasonable to “merge” categories and provide a failure frequency based on a combined number of failures and combining the exposure data. Nevertheless, the failure frequencies established for categories with low number of failures identified must be considered uncertain.

2 Introduction

2.1 Background

Risers and pipelines often contain large volumes of oil or gas at high pressure. Although accidental leaks from risers and pipelines are rare, they have the potential of catastrophic consequences. The cost can be high both in terms of safety and monetary values, and detailed analyses are therefore required. Riser and pipeline failure frequencies are crucial inputs to risk assessments, contingency analysis, environment assessments and regularity studies.

This is the 7th edition of this report, which was first issued in 1988. The first four editions, issued in 1988, 1991, 1997 and 2005, where all in Norwegian, titled "Feildata for rørledninger" and "Anbefalte feildata for rørledninger", while in 2010 the report was issued in English for the first time, as "Recommended failure rates for pipelines" (ref. /2/).

2.2 Objective

This technical report presents available data on failure frequencies for:

- Offshore oil and gas pipelines; both steel and flexible pipelines;
- Onshore oil and gas pipelines; steel pipelines;
- Risers; both steel and flexible risers;
- H_2 and CO_2 pipelines onshore and offshore;
- Offshore equipment included in pipeline systems; and
- Isolation joints.

The frequencies may be applied in quantitative risk assessments (pipeline QRAs/TRAs), availability analyses and contingency analyses. It should be acknowledged that the failure frequencies are produced based on pipeline populations with a wide variety of features. For more detailed failure frequencies for a specific type of pipeline, and/or associated with specific failure modes and mechanisms, it is recommended to do more in-depth assessments of the relevant specific features.

2.3 Changes in this revision of the report

The main changes in this report relative to the 6th edition, which was issued in 2017 (ref. /1/), are as follows:

- Recommended failure frequencies for pipelines are based on more recent data provided by Havtil for offshore pipelines on the NCS, PARLOC and HCRD for offshore pipelines on the UKCS, PSG for onshore gas pipelines, and CONCAWE for onshore oil pipelines.
- Recommended failure frequencies for pipelines transporting CO_2 have been included based on data from PHMSA.
- Recommended failure frequencies for pipelines transporting H_2 has been included.
- For subsea equipment part of pipeline systems failure frequencies are established based on OREDA where available. Failure frequency data for subsea equipment is however limited and, where not available failure frequencies are recommended based on PLOFAM (2) leak model for topside equipment, however adjusted for factors relevant for the subsea environment.
- The report has included a chapter on isolation joints and associated failure frequencies.

- The score grade model applied for establishing length independent failure frequencies for offshore steel pipelines transporting processed hydrocarbons have been revised. This has resulted in changes both to the pipeline characteristics subject to scoring, and updated guidance on score grading.
- In this revision of the report a new score grade model has also been developed for onshore steel pipelines for transportation of hydrocarbon gas. As for the offshore score grade model the onshore score grade model is also based on a set of characteristics, however a different set more relevant for onshore pipelines. The failure frequency contribution per characteristic is assessed to depend on pipe wall thickness, and the empirical frequencies for onshore HC gas pipelines are also established based on wall thickness categories. Onshore HC liquid pipelines are categorised based on pipeline diameter and not wall thickness, and thus the onshore score grade model is thus not directly transferable to onshore HC liquid pipelines.
- Appendix D has been updated as part of this revision. In previous revisions, since 2005, this appendix included background information necessary when estimating failure frequencies for larger pipelines as a result of ship foundering and estimates for failure frequencies due to ship foundering in three different locations. This data is however considered outdated, and in this revision appendix D instead presents a methodology and model for calculating pipeline failure frequencies due to ship foundering. Ship traffic data should be an input to the analysis.

2.4 Notes for future report updates

As for previous revisions, the analysis performed for this current report update has revealed challenges which it is recommended to address in future updates of this report, including:

- Data retrieval and data completeness;
- Incident information quality required for associating incidents with a set of defined pipeline categories;
- Combining data from several data sources;
- Limited information provided for incidents identified, e.g. product transported and hole size information; and
- Failure frequency dependency on type of product transported (e.g. hydrocarbons, H_2 and CO_2).

To establish pipeline failure frequencies, it is important to have a most complete set of relevant historical incidents, as well as a complete set of pipelines (exposure data) for the area and the time period covered by the scope of the analysis. When associating data with a set of pipeline categories, it is vital that the quality of information registered for each event and pipeline is sufficiently good to allocate an event or a pipeline to one of the defined categories.

The experience from this project proves that it is a challenging and time-consuming task to retrieve a complete set of relevant data corresponding to the scope of the study. When searching for data, one challenge is to select inclusion/exclusion criteria to retrieve most relevant events and at the same time exclude most of the irrelevant events stored in the same repository.

Failure to retrieve and filter the relevant data will affect the completeness of the data used when estimating the recommended frequencies. When combining data from several data sources this becomes even more challenging, due to variations in the data registration format. Domain knowledge and a good overview of data repositories are thus considered a vital prerequisite to achieve a solid data basis for frequency estimates.

In addition to the challenges with categorization of events into defined pipeline categories, additional information such as hole size and product transported are often limited. E.g. for the new datasets obtained and reviewed for the updates of offshore risers and pipelines, it has not been possible to retrieve necessary information to establish a hole size distribution.

This report suggests differences in pipeline failure frequencies for pipelines transporting different products, e.g. hydrocarbons, H_2 and CO_2. For several failure mechanisms it may be argued whether the type of product will affect the failure frequency or not. It is reasonable to assume that a pipeline, and various protection systems, will be designed with the transported product in mind. And that variations in material selection and appropriate protection systems should ensure a similar level of safety for pipelines independent of the product transported. Nevertheless, data sources for pipeline transporting different products present differing failure frequencies.

This difference could be related to the product transported, but it could also be related to how incidents are reported and inclusion/exclusion criteria used in the database. Aspects with different products that may affect the failure frequency include: the ability to ensure that composition parameter envelopes are not violated; and the products potential effect on pipeline material properties which can make the material more brittle and thus less robust with regards to third party impact. Re-use of existing pipelines to transport new types of products, i.e. product which the pipeline was not initially designed for, could also affect the failure frequency.

Based on the above it is concluded that there is an uncertainty associated with the pipeline failure frequency dependency on type of product transported. In future updates it is suggested to reassess data sources for pipelines transporting hydrocarbons, H_2 and CO_2, and further investigate the product dependency.

In this revision a new score grade model is developed for onshore steel pipelines transporting hydrocarbons. The score grade model for offshore pipelines has been updated. The score grade models are developed as tools for doing more detailed assessments of characteristics known to affect the pipeline failure frequencies. The objective of the score grade models is to be able to differentiate failure frequencies for pipelines based on actual exposure to such characteristics.

Applying the score grade models requires a substantial amount of information about the pipeline subject to the analysis, and it is recommended that personnel with strong knowledge of the pipeline (i.e. representing the pipeline operator), and personnel with strong knowledge of pipeline technology, operations, and integrity, is involved in the analysis process. It is recommended to at least include such personnel in a type of qualitative hazards identification session.

In future updates it is suggested to request user experience and feedback from use of the score grade models. This can be used to identify potential shortcomings or whether simplifications or clarifications is needed. It would also be beneficial to benchmark the failure frequencies for pipelines obtained using the score grade model. If a reasonably large set of pipelines have been analysed, and unless their exposure to various hazards deviates significantly from an “average” pipeline, it may be expected that the average pipeline failure frequency should not deviate significantly from the “non-graded” average failure frequency.

As part of the development of the onshore score grade model, several aspects related to failure mechanisms, causes and influencing factors specific for onshore pipelines have been identified. One such aspect is differences in how to implement and operate a cathodic protection system for pipelines onshore versus offshore (i.e. due to variations in soil resistivity). In a future update it is recommended to revisit chapter 3 of this report, and ensure the knowledge obtained for onshore pipelines is also reflected in this chapter.

2.5 Abbreviations

CCS	Carbon capture and storage
CP	Cathodic protected
DFI	Design, fabrication and installation
EGIG	European Gas pipeline Incident data Group
EOR	Enhanced oil recovery
ESDV	Emergency shutdown valve
GRE	Glass-Reinforced Epoxy
HC	Hydrocarbon
HCRD	(UK) Hydrocarbon Release Database
HDPE	High-density polyethylene
HIAD	Hydrogen Incident and Accident Database
HISC	Hydrogen induced stress cracking
LOC	Loss of Containment
MIC	Microbiological induced corrosion
MIJ	Monolithic Isolation Joint
NCS	Norwegian Continental Shelf
OREDA	Offshore and Onshore Reliability Data
PARLOC	Pipeline and Riser Loss Of Containment
PHMSA	Pipeline and Hazardous Materials Safety Administration
PLEM	Pipeline End Manifold
PLOFAM	Process Leak for Offshore installations Frequency Assessment Model
PON 1	Petroleum Operations Notice 1
QA / QC	Quality assurance / Quality control
QRA	Quantitative risk assessment
R&D	Research & Development
RIDDOR	Reporting of Injuries, Diseases and Dangerous Occurrences Regulations
ROV	Remote operated vehicle
RP	(DNV) Recommended Practice
SCC	Stress corrosion cracking
SSC	Sulphide Stress Cracking
SSIV	Subsea Isolation valve
UK	United Kingdom
UKCS	UK Continental Shelf
UK HSE	UK Health and Safety Executive
UKOPA	United Kingdom Onshore Pipeline Operators' Association
VIV	Vortex induced vibrations
#	Used to denote number of instances, incidents, events, or similar

3 Failure mechanisms, causes, and influencing factors

3.1 Introduction

There are numerous failure mechanisms, causes and factors which are seemingly influencing the frequency for a failure of a riser and pipeline system. This chapter contains an overview of those failure mechanisms, causes and influencing factors, together with a review of how and to what extent they are expected to affect the failure frequency for riser and pipeline system.

In ref. /26/ two different terms are used for what is in this report is referred to as influencing factors. The term background factor is used to describe static attributes such as pipeline diameter, wall thickness, year of construction, etc, while the term underlaying factors is used to describe variable attributes such as pipeline management, human interventions, etc. Causal connections for several causes, mechanisms, and consequences are listed in Appendix B.

By mapping the relevant causes and influencing factors to the described failure mechanisms, the impact on the overall failure frequency can be described for each cause and influencing factor. Often, however, several causes to a failure and influencing factors are coupled, i.e. likely to coincide. In ref. /26/, Halim et. al. presents the appearance of causal factors in combinations, based on failure data obtained from the Canadian National Energy Board (NEB). When more causes and influencing factors are likely to coincide, it is difficult to separate the extent of the contribution to the resulting failure frequency from each of the coinciding causes and influencing factors. Pipeline diameter, wall thickness, method of manufacturing, transported medium, and location, are one example of a set of influencing factors which are often coupled.

There may also be influencing factors, which if other conditions are kept equal, is found to have an opposite correlation with failure frequency. Such an influencing factor may however be “disguised” if it is coinciding with one or more influencing factors which to a larger extent is correlated with the failure frequency.

Detailed reports for the incidents in the statistics are scarce and since the number of incidents to offshore pipelines are few compared to the population, a narrow categorisation of failure causes into subgroups will lead to unacceptable levels of uncertainties. The information in this chapter is therefore independent from the other parts of the report and contains a general overview of relationships between failures mechanisms, causes, and influencing factors which can be used when detailed risk analyses are performed for specific pipelines.

The main terms that are used in this report when describing failures, causes and mechanisms are:

Cause	An underlying factor or incident which may trigger a failure mechanism is called a cause. Causes can be related to design fabrication, installation, and operations.
Mechanism	For a given cause, a mechanism or process can be started. This includes corrosion, fatigue, plastic deformation, etc.
Defect, damage type	A mechanism results in an observable defect. Defects can be fractures, cracks, pitting, loss of wall thickness and denting.
Failure[7]	A failure arises when a defect exceeds a certain limit state. In this report a failure is defined to correspond to a defect/damage resulting in loss of containment. Equivalent terms which may be used include release, leak, leakage, spillage, loss of containment (LOC).
Failure mode	A failure mode is a mode of materialisation of a damage/defect (pinhole, crack, rupture, etc.). The hole size, leak rate, and leak volume are typically associated with the failure mode.

7 In a different context than this report the term *failure* may also include a situation where a defect is of an extent such that the pipeline integrity is impaired, i.e. that further use of the pipeline is deemed unsafe, however not to the extent where a leak occurs. The term *incident* may or may not involve a failure.

Influencing factor	A condition or physical property which has an influence on the mechanism, e.g. increase or reduce the speed of defect development, and thereby affecting the probability for the mechanism to result in a failure.
Inspection	Inspection gives information about defects and their conditions. This gives an instant picture of the conditions for a pipeline, e.g. regarding possible loss of wall thickness.
Monitoring	Causes and to a certain degree mechanisms can be monitored. Monitoring is a continuous process, e.g. repeated inspections, by which the development of a failure cause or the damage/defect caused by a failure mechanism, e.g. reduction in wall thickness, can be monitored over time. Through inspection and monitoring it is possible to control the development of a defect or damage and thereby enable measures to prevent the defect from developing into a failure.

The relationship between cause, mechanism, defect and failure is given in Figure 3-1. Appendix B include a table presenting an overview of causal relations that can result in failures on a pipeline.

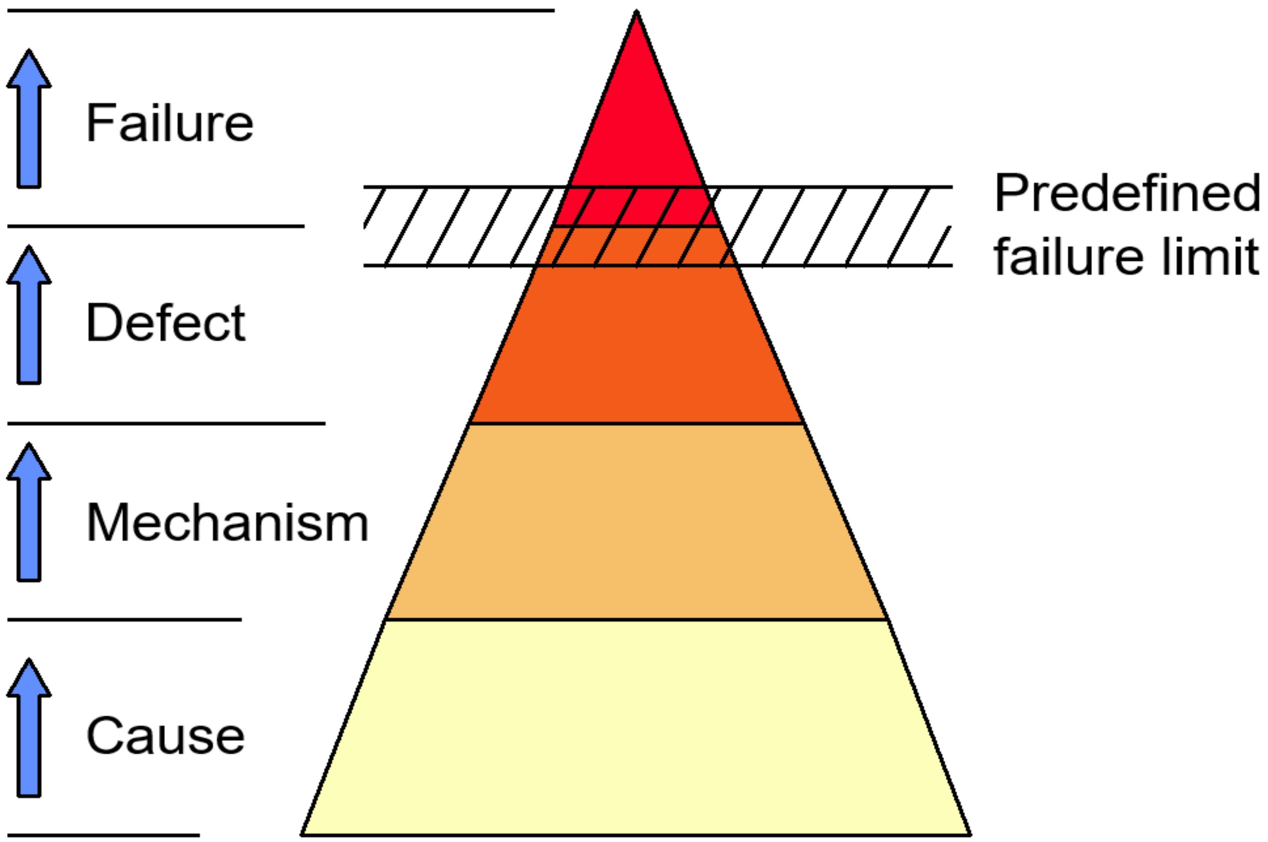

Figure 3-1 Schematic relationship between cause, mechanism, defect, and failure. Failure mechanisms may be influenced by factors increasing or reducing the speed of the defect development. Inspection and monitoring can detect and control failure causes and mechanisms and thereby enable measures to prevent the defect from exceeding the failure limit.

Failure mechanisms, causes and influencing factors are listed in the following subchapters. Some of the aspects discussed will deviate based on transported medium, i.e. processed or unprocessed hydrocarbons, hydrogen or CO_2. Internal corrosion and erosion are examples of a failure mechanism that are assessed to be affected by the type of medium, and factors such as the potential for impurities and sand content. Several other aspects, e.g. external corrosion, external impact, environmental loads and natural hazards, the effect of increase pipeline diameter and wall thickness, etc., are however assessed not to be affected by transported medium.

3.2 Failure mechanisms

3.2.1 Internal corrosion

Corrosion results in loss of pipe wall material, i.e. reduced pipe thickness. If not detected in due time, the pipe thickness may be reduced to a degree where the pipe integrity is impaired, and ultimately that a leak will occur. Both external and internal corrosion can occur, and the two types of corrosion will in general be influenced by different factors. Internal corrosion refers to corrosion resulting in loss of pipe wall material on the inside of the pipeline. Internal corrosion primarily depends on the composition and the presence of possible impurities in the medium.

In general, water in liquid form is a necessity for internal corrosion to materialize. Water may origin from the fluid composition or from gas condensing into liquid under certain pressure and temperature conditions. To avoid internal corrosion, the water concentration must be known and monitored in the process. Even dry gas can develop liquefied water under certain operational conditions and water concentration must therefore be meticulously monitored to mitigate corrosion.

Bacteria from impurities in the fluid may cause microbiological induced corrosion (MIC), e.g. through bacterial metabolism producing aggressive substances such as sulphides, sulphuric acid, nitric acid, or organic acids. MIC can lead to rapid pitting attack, and can occur in various materials including carbon steel, cast iron, copper and copper alloys, stainless steel, nickel and certain nickel alloys, aluminium, and concrete. Bacterial corrosion is a concern mainly for infield pipelines and water injection lines, i.e. pipelines with high water content, and potential impurities.

A pipeline may be more prone to internal corrosion if certain a condition occurs in combination with the fluid composition. Such conditions may e.g. be pressure and temperature for which H_2O liquifies. If such a condition is present the likelihood of corrosion to materialise in a part of the pipeline is considered independent of the pipeline length. It is observed that when internal corrosion is an issue, this is often located a few kilometres downstream the pipeline starting point. In a pipeline specific location where changes in temperature and pressure cause condensation and where the temperature is high enough to cause corrosion. After a few additional kilometres, the probability for internal corrosion is likely to decline.

Export pipelines for oil and gas in the North Sea generally transports media processed or prepared (corrosion inhibitor) in such a way that corrosion is effectively mitigated, and development of severe internal corrosion in these pipelines is therefore unlikely. Infield well-stream pipelines are more prone to internal corrosion since the fluid are often a mixture of oil, gas and water under high pressure and temperature with aggressive elements such as carbon dioxide and hydrogen sulphide. These circumstances might be one of the reasons why small diameter pipelines are more prone to failure due to internal corrosion than large diameter pipelines.

For CO_2 pipelines it may be more challenging to keep the fluid composition within design specifications, as compared to HC pipelines. The consequence of impurities is also potentially higher for CO_2 pipelines. Impurities that together with CO_2 could cause severe corrosion are water, H_2S, NO_X, SO_2, O_2 and solvent.

Although corrosion may seem to be most relevant for steel pipelines and risers, end couplings for flexible risers and pipelines are also exposed to internal and external corrosion. Wires in flexible pipelines and risers are also exposed to corrosion; this is described in more detail in chapter 3.2.3.

3.2.2 External corrosion

External corrosion refers to corrosion resulting in loss of pipe wall material on the outside of the pipeline. External corrosion primarily depends on the quality and function of the corrosion preventive actions or systems in use. Offshore steel pipelines are generally less prone to external corrosion than land steel pipelines

For offshore pipelines, it is considered unusual to have external corrosion to such an extent that safety or availability is affected. The high and even conductivity of seawater together with coating and sacrificial anodes provides a reliable protection for offshore pipelines against external corrosion.

For onshore pipelines the earth's conductivity varies, and the method of applied voltage is a more complicated method for corrosion prevention. Cathodic protection is normally applied for onshore pipelines. External corrosion is however more likely to be found on onshore pipelines than on offshore pipelines. For risers in the splash zone and pipelines on land, anodes cannot be applied. For risers, it is crucial that the coating is intact and inspected regularly.

External corrosion is assessed not to depend on transported medium, i.e. hydrocarbons, Hydrogen or CO_2.

3.2.3 Corrosion on flexible pipeline wires

A flexible pipeline consists of several layers, including metallic layers, anti-wear layers, and fluid barriers (coating). Metallic wires are used as armour in flexible pipelines and risers, and corrosion on such metallic wires may occur if sea water enters the structure as a result from coating damage. This will in most cases be related to external interference but may also occur if an internal pressure in the pipe structure punctures the coating. Experience has shown that the corrosion will occur close to the damaged area, and with no relevant extent along the pipe structure.

Corrosion on wires may also come as a result from diffusion of H_2S or CO_2 through the pressure layer. Insufficient access to oxygen will however normally lead to that such corrosion attacks are being limited. However, even small corrosion pits will create a concentration of tensions that under dynamical restrictions might lead to wire fractures.

3.2.4 Fatigue

Fatigue is a mechanism initiated e.g. by vibrations or cyclic loading and will occur in pipe systems when the combinations of static and dynamic stresses in the piping components exceed allowable values. Static stress in the pipe is commonly caused by a combination of pressure and thermal growth. Dynamic stress can result from vibration transmitted by connected machinery, forces generated inside the pipe from water hammer or pressure pulsations, or by fluid induced or other external loads. Fatigue may lead to crack formation in steel. Excessive vibrations or cyclic loading leading to fatigue may be the result of poor design or installation works.

In flexible pipelines and risers exposed to dynamic loads, fractions caused by fatigue can arise in the zeta wire, especially at potential welds or surface damages on the wire. Fatigue fractures in the armour wires may also be experienced. The most relevant fracture locations will be connected to welds or surface defects on the wires, or close to the end couplings or bend restrictors. It is not considered probable that a fracture in a wire caused by weakness in a random part of the pipe will lead to any further damage development. However, if this were to occur in a coupling between firm and flexible material related to an end coupling or a bend restrictor, the probability that the development of the damage will continue by a transfer of the loads to adjacent wires must be considered higher. If this is the case for an end coupling, it is possible to imagine a development that would lead to a rupture, although such accidents are not known from history.

For hydrogen pipelines, hydrogen gas or hydrogen blended with natural gas will significantly reduce the fatigue crack growth resistance and fracture toughness of pipeline steels. There is a long-term integrity risk due to fatigue and therefore a need for careful management of pressure fluctuations.

3.2.5 Hydrogen embrittlement and hydrogen induced cracking

In terms of hydrogen and its influence on pipeline steel materials, the primary concern is the development of hydrogen embrittlement (HE), which can lead to a reduction in the resistance against crack nucleation and growth. This can increase susceptibility of pipeline materials to defects and reduce resistance to the pipeline against cyclic loading, large static loads, slowly varying loads, and accidental scenarios. HE can ultimately govern acceptable pipeline utilization and design. Secondary effects and concerns include the impact of reduced ductility and general utilization of the pipeline and potential implication on corrosion rates and how corrosion pits may accelerate the susceptibility of materials to HE.

Hydrogen induced stress cracking (HISC) can occur in martensitic steels (13%Cr) and ferritic-austenitic steels (duplex and super-duplex). Blisters of free hydrogen can create cracks in steel or weld at a CP/anode location when the steel is exposed to seawater and stresses from the buckle. The pipeline utilization does not have to necessarily be excessive.

At particular high levels of H_2S in the well flow, there might be a risk of hydrogen brittleness of the zeta and armour wires as a result from diffusion through pressure layers. This may later lead to wire fraction. For the known levels of H_2S concentration in the North Sea, this is not regarded as a problem.

3.2.6 Plastic deformation of steel

A pipeline may experience deformation if exposed e.g. to external interference such as excavation works (onshore) or impact from dragged anchor or trawl board (offshore). Ground movement e.g. due to landslides or earthquake can also cause deformation. Plastic deformation can e.g. be in the form of a dent, extreme bending of the pipeline, increased ovality, and stretched or even torn apart pipeline.

Failure mechanisms related to plastic deformation can be of immediate nature, meaning that the time between initiation of applied load and the failure is short. In such cases inspections will have little effect on pipeline availability.

An applied load may also cause minor to moderate deformation which will make the pipeline more susceptible to other failure mechanisms and develop into failures if not detected and dealt with within the required time frame. There are examples of anchor damages which have developed into leaks after some time, making regular inspections an important tool for detecting and planning the corrective maintenance.

Acceptable deformations for operation with hydrogen gas may be affected by the negative effect of hydrogen on pipeline material, which may lead to reduced ductility in permanently deformed local regions with high strain.

3.2.7 Deformation of flexible pipeline material

The following deformation processes are known for flexible pipelines and risers:

- Delamination and leak between flexible pipe and nipple, i.e. problems with the coupling between fixed and flexible element
- Blistering of rubber materials and plastics because of gas diffusion
- Missing binding in layers (bonded pipes)
- Fraction in wires, spiral and internal coating
- Collapse or ovaling of the pipe structure by quick pressure relief
- Damage from overload and bending

The above failure mechanisms can result in leaks through layers or through the whole pipe structure. Leaks in pressure layers happens when the pressure layer withdraws itself from the contraction connection in the end coupling. The problem normally relates to pipes with a relatively high service temperature and where Coflon (HDPE) is used in the pressure layer. Changes in the plastics develop over time as the softener disappears. This increases the firmness and reduces the fraction extension. The pipes will experience temperature and pressure cycles connected to shut down and possible regulations. This leads to heavy forces in the length direction of the pipeline and may also cause free movement of the layers relative to each other, and that the pressure layer withdraws from, or breaks, at the fastening point. This may cause a leak so big that a potential drainage of gas cannot handle the pressure in the pipe structure, and the external coating is punctuated. The leaks will normally be limited because of the flow resistance out of the pipe structure.

If weakness in the pressure layers or irregularities in the zeta spiral has occurred, it may be possible that this will result in a leak over time, although it has not been registered through pressure testing. The pressure testing is executed at low temperature, and the reduced strength and the flow resistance in the plastics at a high operation temperature may result in that a weakness leads to a leak during operation. In case of an irregularity in the zeta spiral, the pressure layer may, if exposed to high temperature and high pressure over a certain time period, be “extruded” out of the irregularity and thereby cause a leak. As for the situation above there is no reason to expect a full rupture or a major leak.

3.2.8 Erosion

Internal erosion can result from sand production. At production flows with a high level of sand quantity, there will be a possibility for wear inside the pipe. Normally sand production is expected, and if deemed necessary the pipe is designed with an inner carcass to resist the wear.

3.3 Failure causes

3.3.1 External interference

External interference to offshore pipelines includes e.g. impact from trawl board, dropped or dragged anchor, and other dropped objects hitting the pipeline. Offshore pipelines located in areas with trawling activities, and high vessel traffic will be most exposed to impacts from trawl boards, dropped or dragged anchor. Offshore pipelines in the vicinity of an installation, where lifting activities are performed, will be most exposed to objects dropped while being lifted between the installation and a supply vessel.

External interference to onshore pipelines includes e.g. excavation works if buried, or exposure to traffic if over ground. Both onshore and offshore pipelines may also experience mechanical defect failure due to nature and environmental loads such as e.g. landslide and earthquake. External interference also includes fires exposing the pipeline.

In general, failures related to external interference are linked to conditions and activities which a specific pipeline is exposed to. The probability of different types of external interference may thus vary significantly along the pipeline. Dividing the pipeline into different sections, exposed to specific activities or conditions is therefore reasonable when establishing failure frequencies linked to external interference. An example may be probability of impact from dragged anchor, which is expected to correspond with vessel traffic intensity and sea depth. An area with reduced or strictly controlled activities will lead to a reduction in failure frequency for pipelines, when compared with a less controlled area with a similar activity level.

In addition to a decline in overall failure frequencies reported for onshore HC pipelines (ref. /15/, /16/, /18/) the relative fraction of failures associated with the cause external interference is also significantly reduced. It is reported that this is likely associated with more stringent enforcement of land use planning and the application of on-call systems for digging activities of external parties. External interference is assessed not to depend on transported medium, i.e. hydrocarbons, Hydrogen or CO_2.

3.3.1.1 Steel pipelines

A pipeline's load resistance against external interference primarily depends on the pipeline diameter and wall thickness. In general, for pipelines of equal design pressure and material properties, the wall thickness will increase proportional to the diameter of the pipeline. Both diameter and wall thickness will contribute to increased load resistance against external interference. For onshore steel pipelines in Europe (ref. /15/) and UK (ref. /18/) statistics shows that for pipelines with wall thickness exceeding 15 mm failure due to external interference is negligible, while for pipelines with wall thickness between 10 – 15 mm the failure frequency due to external interference is an order of magnitude less than for pipelines with wall thickness less than 5 mm. There are however examples of ruptured pipelines due to external interference from special purpose cutting and grinding machines used to even and homogenize ground.

3.3.1.2 Flexible pipelines

Some failures with flexible pipelines and risers can be traced back to damages caused by dropped objects, wear from crossing pipes or wires. Damage to external layers of plastics or rubber coating can result in penetration of water, which will again cause corrosion in the armour layers. This process happens over time and will cause leaks, but it can also result in a full burst of the pipeline. Flexible pipelines are also susceptible to fatigue, wear and tear. Fatigue, in particular for risers, may be caused by environmental forces and affect both the pipe body material, end couplings, and sealings.

3.3.2 Ground movement

Ground movement can lead to significant plastic deformation of a pipeline. Earthquake and landslides are examples of ground movement which can affect both onshore and offshore pipelines. Flooding from extreme rainfall may also wash out the foundation for onshore pipelines.

3.3.3 Design and construction errors

Gross errors made during production are likely to be detected and solved, however errors resulting in smaller defects or material weaknesses may only be evident at near maximal operational temperature and pressure. Smaller defects or material weaknesses can therefore be detected early if the pipe from start is exposed to the conditions governed by design. This is however not always the case and construction errors may therefore develop into extensive damages at an early stage, i.e. within the burn in period (see chapter 3.4.8).

The pipeline design may vary depending on transported medium. However, if complying with the applicable pipeline design codes, it is assessed that the probability of failure due to design and construction will be at a similar level regardless of transported medium.

3.3.3.1 Steel pipelines

Errors made during production of steel pipelines includes unacceptable strain or bending of the pipe due to unrestrained thermal expansion, inadequate or faulty constructed fixed points or pipe geometry. Pipelines with a large D/t (diameter over thickness) factor is expected to be more vulnerable to unacceptable strain.

Errors such as missing support, missing fixed points, too much expansion or too little coverage are important issues close to platforms and in the landfall zone for offshore pipelines. For pipelines onshore similar errors are important issues in relation to bends and road crossings.

Construction errors are found to be the cause of a large part of failures for large pipelines on land. Compared to an offshore pipeline, there are in general a large number of crossings with roads, railroads, channels etc. It is therefore reasonable to assume that these kinds of failures are more common for onshore pipelines than for the corresponding offshore pipelines. Crossings with other pipelines is however something that should be given extra attention irrespective of the pipe being onshore or offshore. At a pipeline crossing, the distance between the two pipelines must be adequate so that they can cause no damage to each other. The distance must be assured during lay but also during operation as pipe movements can occur.

Stress corrosion cracking refers to an increased likelihood of cracks formation in a corrosive environment if the material is subjected to tensile stress. Tensile stress is a state caused by a load stretching the material in the axis of the applied load, i.e. stress caused by pulling the material. Tensile stress can be a result of e.g. residual cold work, welding, grinding, and thermal treatment.

3.3.3.2 Flexible pipelines

Due to production aspects, mainly unbounded flexible pipes are used in offshore pipelines and risers. Bonded pipes have restrictions on length, normally dimensions up to 16” and lengths of about 200 metres are produced. Errors made during production of flexible pipelines includes:

- Incorrect amount or mixture of Epoxy
- Incorrect material type
- Faulty installation of end couplings
- Moisture in the construction during installation of end couplings and injection of Epoxy
- Incorrect welding quality
- Bending of pipelines that exceeds specified limits
- Insufficient binding between the layers at vulcanization

3.3.4 Material, weld and manufacturing errors

Errors made during manufacturing and welding will affect the material properties and reduce the integrity and robustness of the pipeline material. Such errors can be mitigated by adequate quality checks with extensive testing and monitoring of all processes related to the material, manufacturing of pipes and welding. Mistakes originating from manufacturing, that are not discovered during testing rarely cause an immediate failure. Manufacturing errors may however develop into extensive damages at an early stage, i.e. within the “burn in” period (see chapter 3.4.8).

The probability of manufacturing errors is in general dependant on e.g. the volume of material and number of welds (for steel pipelines). E.g. the weld failure frequency will increase with increasing number of welds. The probability of one or more errors made in construction of one pipeline is however also dependant on the e.g. manufacturing method and quality control procedures, which is not proportional to e.g. volume of material and number of welds. Whether there is an error with one or multiple welds, a failure occurring in one weld will typically result in all welds being inspected, controlled, and replaced if necessary. The likelihood of failure within the pipeline, due to poor execution or quality control of welds, will thus be increasing, however likely not proportional to the number of welds.

Large diameter pipes (diameter > 24”) are normally manufactured through rolling plate and welding of seams which enables methods well suited for quality control of both roller procedure and dimension.

Small diameter pipelines are however normally manufactured as seamless pipes, formed by drawing a solid block of pipe steel over a piercing rod to create the cylinder. Performing continuous quality checks of the internal surface of the pipe may in this case be more complicated and there is potential for disequilibrium in material distribution in the pipe wall. These issues are further discussed in Appendix A.

Based on the discussions above, different failure frequencies related to material and weld defects may apply depending on if the pipe is a seamless one (small diameter pipes) or a rolled plate pipe (large diameter pipes).

In addition, it can be noted that the actual procedures for quality control of joint welds most likely are carried out under more favourable conditions when performed on a pipe laying vessel than when carried out in situ when laying pipes onshore. Material and weld defects are further discussed in Appendix A.

3.3.5 Operational error, or operation outside of design specifications

A pipeline system is design for a particular type of operation, i.e. with a design pressure, material properties and dimensions, and protection systems, that are adequate for the intended use and material being transported. If, however, the pipeline is operated under conditions deviating from the design specifications then the pipeline safety target level may not be met. The pipeline may be operated under conditions deviating from the design specification due to an error made by the operator, or due to deliberate changes in operation where the design specifications are not known, not understood, or for other reasons not adhered to.

If a pipeline is operated outside of design specifications, certain failure mechanisms may be accelerated and result in pipeline damage developing faster than expected, and a pipeline failure may develop before scheduled inspection is performed.

Operational errors also include failure to implement corrective action if inspections reveals that the pipeline integrity is reduced, i.e. lack of integrity management.

3.4 Influencing factors

3.4.1 Transported medium

In previous revision of this report, several sources used are pointing out that pipelines carrying oil are more prone to failures than corresponding pipelines used for transportation of gas. The difference between the most recent onshore natural gas failure frequencies provided by EGIG (ref. /15/) and onshore crude oil failure frequencies provided by CONCAWE (excluding theft incidents, ref. /16/), is however less than 10 %.

The same sources for onshore natural gas and oil pipelines also shows that corrosion as a source of failure has been reduced significantly over the time period covered by the data sources (~1970-2020). The reduction is however more evident for oil pipelines, a reduction which is linked to significantly less use of hot oil pipelines which were significantly more prone to corrosion failures than cold oil pipelines, likely due to the application of thermal insulation[8]. With a reduction in failures caused by corrosion, the total failure frequency is to a larger degree associated with causes less affected by the transported medium. Data for CO_2 pipelines gathered by PHMSA and compiled and presented by Vitali et. al. (ref. /20/), also indicates that the failure frequency for onshore pipelines transporting CO_2 used for enhanced oil recovery in the US have failure frequencies similar to onshore pipelines transporting hydrocarbons.

8 Damage to the insulation will lead to water ingress in the warm space between the pipe and the insulation, causing suitable conditions for external corrosion.

Previous data provided by PARLOC in 2001 and 2012 (ref. /4/, /5/) differentiates between infield pipelines, typically transporting well stream, and processed hydrocarbons. In the latest PARLOC report (ref. /3/) such a differentiation is not explicitly given. There is however a significant difference in failure frequencies for pipelines shorter than and longer than 10 km. It should be noted that the report states, “Although the LOC frequency cannot be directly dependent on the pipeline length, it acts as a proxy for many other factors”, “Pipeline length is a proxy for numerous other factors that affect LOC frequency e.g. diameter, wall thickness”, and “The longer pipelines are typically large diameter dry gas or stabilized crude/condensate transmission pipelines whereas the shorter pipelines are mainly smaller diameter carrying corrosive unprocessed well fluids” (ref. /3/).

The difference between well stream and processed hydrocarbons is the presence of impurities, i.e. various chemical compounds that are likely to develop corrosive environment under certain process conditions. The possible addition of other aggressive components to the media being transported will influence the estimated corrosion potential. For pipelines and risers transporting processed, dry, and non-contaminated gas, the potential for internal corrosion is very limited, as opposed to pipelines transporting oil or gas with free water or significant amounts of CO_2 or H_2S.

The presence of impurities is also an important topic of concern for CO_2 pipelines (ref. /24/, /25/). Keeping the CO_2 composition within design specification, i.e. for CO_2 pipelines, could be more challenging compared to process HC. The consequence of impurities is potentially higher for CO_2 pipelines than for HC pipelines due to an expected higher rate of corrosion. Impurities that together with CO_2 could cause severe corrosion are water, H_2S, NO_X, SO_2, O_2 and solvent.

For hydrogen pipelines, the potential for hydrogen embrittlement and the risk of adverse effects on the integrity of C-Mn pipelines is widely recognised. This includes loss in tensile strength and ductility, reduced fracture toughness and accelerated fatigue crack growth, affecting the design and utilization of the pipeline.

The factor transported medium are often coupled with other factors known to affect pipeline failure frequencies. Variations in failure frequency found for pipelines transporting different type of medium may thus be associated with other factors as well. In many cases gas pipelines have larger higher design pressures, and therefore also larger wall thickness, than oil pipelines. Pipeline location can often be linked to the medium being transported. Gas pipelines are often found to be main lines, transporting gas over long distances, while oil pipelines on the other hand are often shorter connecting units within a field. Pipeline wall thickness and location are discussed in chapters 3.4.6.1 and 3.4.7.

3.4.2 Installation method and activities

Small diameter pipelines are often buried (trenched) during installation. The trenching tool and operation itself may pose a threat against pipeline integrity and damages to pipelines derived from the laying and trenching operation has occurred /8/. However, for small and medium pipelines in operation it is assessed that the mitigating effect of trenching, reducing the potential for damages due to trawling or dropped objects, is a benefit for the overall pipeline loss of containment risk.

3.4.3 Corrosion prevention

The method for corrosion prevention is an important aspect during the design phase of pipeline and the likelihood for corrosion strongly depends on location. Data for onshore pipelines shows that external corrosion is significantly more frequent than internal corrosion; EGIG (ref. /15/) reports a factor 8, UKOPA (ref. /18/) reports a factor 20 (excluding stress corrosion cracking), and CONCAWE (ref. /16/) report a factor 2 (considering cold oil pipelines only).

For offshore pipelines the system for preventing external corrosion is more effective and reliable since the surrounding seawater provides stable conductivity which is a requirement for effective protective anodes. Compared with onshore pipelines a larger proportion of the offshore pipelines carry unprocessed gas or oil, and thus offshore pipelines are generally more prone to internal corrosion development (ref. chapter 3.4.1).

Data from gas pipeline networks in the USA (ref. /8/) illustrates the importance of corrosion prevention. Between 40 % and 50 % of all failures described as corrosion are found on the 15 % of the pipeline network lacking corrosion prevention. In addition, the frequency for failure due to corrosion on pipes with cathodic protection is only about 1/6 compared to the corresponding frequency for pipes without cathodic protection.

3.4.3.1 Sacrificial anodic protection

For offshore pipelines mounted anodes are designed to prevent external corrosion and may be replaced or changed in case of abnormal rate of degradation before external corrosion reaches critical levels. The sacrificial anodic protection is made of a more active and less noble metal than that of the pipeline material itself, e.g. zinc or aluminium. This is a material which is more easily corroded, and thus will sacrifice itself, while protecting the pipeline body from corrosion.

3.4.3.2 Cathodic protection

For onshore pipelines a system with applied voltage is used to prevent external corrosion. To confirm the system function, CP-measurements (cathodic protection) must be carried out. The CP-measurement is basically a measurement of the electric potential between the pipe and the surrounding medium, earth or water for example.

For failure data for onshore gas transmission pipelines in the US (ref. /29/) in the period 2002 – 2013 approximately 10 % of the failures caused by external corrosion occurred for pipelines which did not have cathodic protection. The fraction of pipelines without cathodic protection where however only about 1 %. This demonstrates the effectiveness of cathodic protection on external corrosion.

3.4.4 Pipeline material

For pipelines made of steel there is a recorded increase in failure frequency with increased material strength (ref. /9/). This effect is significant, however when other conditions are equal it is unlikely that increased material strength will have a negative effect on the failure frequency. This might however be because increased material strength is associated with a relaxation in design safety factors and due to a more rapid development of corrosion than was anticipated as a result of product sourness.

When other conditions are equal, increased material strength may also coincide with narrower wall thickness. Thus, the pipeline will have a reduced ability to withstand external interference, and the duration for an initiated corrosion to become critical is shorter. Increased material strength also increases the frequency for several other failure mechanisms. These are further discussed in Appendix A.

Available data on flexible pipelines is limited. However, according to the recent PARLOC 2020 report (ref. /3/) the failure frequency for flexible pipelines is approximately 2.5 times higher than for short steel pipelines (i.e. less than 10 km). Compared with longer steel pipelines, the failure frequencies for flexible pipelines are 1-2 orders of magnitude higher.

3.4.5 Material utilisation factor

The material utilization factor describes the relationship between the tension in the tangential/circular direction of the pipe due to the pressure difference between inside and outside and the material strength (Specified Minimum Yield Stress). For pipelines on land, this factor is normally found in the interval 0.4-0.8. For offshore pipelines the factor is normally found in the interval 0.72-0.85, and lower for risers.

A high utilization factor will result in a more rapid corrosion, and thus if not detected corrosion will result in a failure within a reduced time period. Other parameters are however likely to be coupled with a high utilisation factor. E.g. an increased difference in pressure between inside and outside, large diameter, and low material strength, will typically lead to increased wall thickness. The increased wall thickness will allow more corrosion in absolute numbers, making the pipe more robust (ref. chapter 3.4.6.1).

If corrosion has resulted in reduced thickness or even penetrated a limited area of the pipe wall, this will normally not affect the pipe's ability to withstand the pressure difference resulting from high utilization. When the remaining wall thickness is reduced over a larger area the utilization factor will however be of great importance. In this case the wall may no longer withstand the pressure difference and the reduced wall thickness in combination with high utilization may result in a rupture.

With a low utilization factor a large proportion of the material must be corroded to cause rupture. If the corrosion is uneven, it may just as well lead to a leak at one spot instead of resulting in a full rupture. If the corrosion is local and limited to a small area (pitting), a leak before rupture can be anticipated, regardless of utilization factor.

For other failure mechanisms, e.g. impact, actual wall thickness is an important factor. When increasing the wall thickness, reaching the level of impact force necessary to cause a rupture is less likely. Variations in utilization factor will in this case however have low effect on ability to withstand impacts.

3.4.6 Size

Pipeline size can be measured in terms of length, diameter, and wall thickness. These parameters are often coupled. Large diameter pipelines are often used for transporting pre-processed fluid over longer distances. Gas is more often transported over long distances, and due to high pressure, such pipelines will normally have a large wall thickness (ref. /17/). Small diameter (offshore) pipelines are often transporting well fluid and found in the near platform zone, with higher traffic density, more likely to have impurities resulting in internal corrosion, and more exposed to external interference.

3.4.6.1 Wall thickness

Wall thickness is considered an important factor with regards to failure prevention. Large wall thickness will increase the pipeline robustness with regards to impact loads. Both internal and external corrosion result in a gradual deterioration of the pipe wall thickness, generally at a limited area. The thicker the wall, the longer it takes for initiated corrosion to cause failure or rupture of the pipeline, hence providing a larger time slot for corrosion to be detected before resulting in failure. Increased wall thickness also makes the pipeline more robust with regards to external interference such as excavation. The effect of wall thickness in relation with corrosion and external interference is presented in the most recent EGIG and UKOPA failure data reports (ref. /15/, /18/).

3.4.6.2 Diameter

There are several sources pointing out that failure frequency for risers and pipelines decrease with increasing diameter /8/, /9/, /15/, /16/, /18/. The data underlining this fact originate from different geographical locations and for both gas and oil pipelines.

Pipelines with large diameter tend to have a larger load resistance against external interference and can withstand more corrosion (in absolute terms) than small diameter pipelines. Records point out that the proportion of failures caused by corrosion is larger for small diameter pipelines than for large diameter pipelines.

Whether or not the pipeline diameter, as an isolated parameter, influences the failure frequency is however uncertain. Large pipe diameter is a factor very often coupled with large wall thickness. Large diameter pipelines are also often used for transport of processed fluid over longer distances. For unprocessed well fluid smaller diameter pipelines are used.

Records from the USA and Western Europe show a distinct decrease in failures related to corrosion with increasing pipeline diameter and wall thickness. Large diameter and wall thickness will increase the likelihood of discovering corrosion by pigging. This is partly because current pigging equipment is better suited for large diameter pipelines and partly because the large diameter pipelines generally has got larger wall thickness. Larger diameter, and very long transportation pipelines are in general also more expensive, and it is expected that they will be better monitored, maintained and controlled compared to small / shorter lines. Loss of integrity of a large diameter pipeline will often result in more severe HSE implications, and downtime for large diameter pipelines will more often lead to significant cost due to lost production.

3.4.6.3 Length

According to PARLOC (ref. /3/) failure frequencies (per distance) are correlated with the length of the pipeline, i.e. the failure frequencies per pipeline km-year is lower for long distance pipelines compared with short distance pipelines.

Pipeline length is a factor very often coupled with both pipe diameter, wall thickness, and medium transported. Long pipelines are normally larger in diameter, larger wall thickness, and mostly transporting processed fluids. Therefore, long pipelines are generally more robust with regards to reduced wall thickness as well as less exposed to corrosive fluids. The isolated effect of the pipeline length is thus hard to determine.

For smaller diameter and shorter length infield lines, transporting unprocessed hydrocarbons, a somewhat increased length of the pipeline will result in a larger pressure / temperature spectrum over the pipeline length. This could increase the probability of having an ideal combination for bacteria to grow.

3.4.7 Location

Variations in failure modes and frequencies due to variations in location are notable. There are obvious differences in surrounding conditions between onshore and offshore pipelines. One could however argue that failure frequencies related to material defects and internal corrosion are independent of whether the pipeline is located onshore or offshore but frequencies for any other failure mode will vary depending on location.

For offshore pipelines, there is a distinct difference in failure frequency for pipelines located within the near platform zone and for pipelines located a certain distance away from the platform or fields, ref. /3/, /8/, /9/. The failure frequencies are found to be higher in the vicinity of the platform. This may amongst other reasons be due to construction activities in the area and lifting activities e.g. to and from supply vessels.

The probability of impact to pipelines in the vicinity of the installation, due to installation specific activities, is assessed to be independent of how far extends from the installation, i.e. the pipeline length. The fraction of a pipeline which is in the vicinity of the installation is however obviously decreasing as the pipeline length increases. The contribution to the failure frequency, measured per pipeline-km, will thus be lower for long pipelines compared with short pipelines.

When evaluating different sets of data, local conditions that cause variations to the failure frequencies must be considered. In the Gulf of Mexico the likelihood for waterspouts, landslides etc. is larger than in many other parts of the world. The frequency for failure to offshore pipelines due to forces of nature is for thus higher than for e.g. the North Sea. Compared to the North Sea, the Gulf of Mexico also shows an increased frequency for failures related to corrosion. This may be due to the higher temperature in surrounding waters and/or the higher age for parts of the pipelines and corresponding standards for design and corrosion prevention.

Different sections of a risers, i.e. below water, in the splash zone, and above water, are typically exposed to different loads and effects depending.

There is an increased level of uncertainty in the area where offshore pipelines approach shore and become onshore pipelines. In this area, two zones can be defined: the landfall zone and the tidal zone. It is likely that there is a slight increase in likelihood for external interference in the landfall zone compared to the midline stretch. In the tidal zone, the likelihood for dropped objects (anchors etc.) can be assumed to be low but instead there will be an increase in likelihood for corrosion due to frequently shifting exposure to water and air.

For onshore pipelines, there is a recorded increase in failures related to corrosion in the transition from buried to not buried and at crossings of roads and railroads /8/.

3.4.8 Age

Existing reports are fairly uniform when concluding on the impact of pipeline age on failure frequency /8/, /9/. The pipelines normally go through a burn-in period where the failure frequency is higher than during the remaining part of design life where the failure frequency is approximately constant.

During the burn-in time, an increased failure frequency related to external interference, operational issues, material failure and defect welds are recorded.

During the burn-in period the pipeline will be exposed to loads and tensions which will reveal fabrication related defects in material or welds. An above average failure frequency related to external interference, operational issues, material failure and defect welds are recorded. The burn-in period will also often coincide with a higher activity level in the surrounding area, subsequently leading to an increase in frequency for falling objects etc.

A potential increase in failure frequency for older pipelines is likely to be linked to the year of construction just as much as the actual age (ref. /17/). During the seventies, several extensive R&D projects focusing on steel and pipe production, resulting in a substantial increase in the quality of pipelines. In addition, knowledge within fracture mechanics and quality assurance were further developed. This work resulted in new and improved standards for qualification of steel pipes, manufacturing, welding technology, qualification of welds, non-destructive testing and acceptance criteria.

Regarding onshore steel pipelines transporting gas, EGIG (ref. /15/) concludes that for pipelines constructed after 1964 no significant changes in failure frequencies exist as a function of pipeline age. CONCAWE (ref. /16/) states that for onshore steel pipelines transporting oil pipelines there is no evidence that the ageing of the pipeline system implies a greater risk of a leak. The report states that the development and use of new techniques, such as internal inspection with inspection pigs, have played a role in maintaining safe and reliable operation of pipelines, and will continue to be an essential tool in the future.

For flexible pipelines and risers aging thermoplastics / rubber can affect the material properties and ability to withstand for example external interference.

3.4.9 Operation and maintenance

Faulty operation of the platform or terminal may e.g. result in the presence of water, increased fractions of impurities, and/or pressure or temperature outside design specifications. These are factors which will affect the potential for corrosion and the likelihood of failure due to e.g. corrosion.

If severe corrosion and substantial loss of wall thickness is detected, the operational pressure may be lowered so that corrective maintenance can be planned before a failure occur, and effects of production disturbances is reduced. For internal corrosion, other measures such as increased use of corrosion inhibitor may help to decrease or stop the rate of wall thickness reduction.

Stress corrosion cracking, as discussed in chapter 3.4.2 may also be a result of internally and externally pressure loads, expansion due to heating, and other loads applied during service.

3.4.10 Monitoring and inspection

Through inspection and monitoring it is possible to control the development of a defect or damage and thereby enable measures to prevent the defect from developing into a failure. As discussed in the previous chapters, various influencing factors are contributing to increase or decrease the speed of the potential failure mechanisms. What monitoring and inspection methods to use for a specific pipeline, and the inspection frequency, should thus be evaluated in each individual case.

Often the monitoring methods used are measuring change in a process related to the failure mechanism rather than the development of the defect potentially resulting in a failure. E.g. water content is measured to prevent corrosion, and movements and vibrations are measured to prevent fatigue. If operational conditions suddenly change, monitoring is important to reveal the initiation of potential harmful processes caused by the change.

The following monitoring methods are applicable for pipelines in general:

- Pressure and temperature monitoring
- Dew point measurements
- Measurements of inlet and outlet composition
- Corrosion measurements through use of e.g. corrosion probes which gives an indication of corrosion rate
- Accelerometers at free spans for monitoring of movements (not often used)

In general, there are two fundamental approaches for pipeline inspection, external visual inspection, and internal inspection using an intelligent pigging tool. For offshore pipelines, external visual inspection is done using remotely operated vehicles (ROV) or divers that collect data either through camera recordings or sonar.

External visual inspection comprises:

- CP (cathodic electric potential) measurements, and when applicable, visual inspection of anode consumption rate
- State of pipeline coating (damages)
- Location of the pipeline (stability and displacement)
- Supports (free span)

Intelligent pigging is performed by inserting a pigging tool into the pipe and letting it travel along the stretch to be inspected. The pig is equipped with various instruments for the necessary measurements and normally comprises:

- Wall thickness
- Location of the pipeline (with geo-pig)
- Cross section anomalies (e.g. dents (with calliper-pig))

In general, intelligent pigging provides reliable and precise information but the method may be costly. Typical inspection intervals may be every 3 years to 15 years. Note also that there is a large number of pipelines that are not possible to send a pigging tool through.

Loss of wall thickness due to corrosion is best registered when the corrosion is evenly spread out as opposed to pitting. Cracks caused by material or weld defects which are not discovered at early inspections or tests are difficult to reveal through intelligent pigging. Loss of wall thickness can be inspected and if logged, and the rate of degradation can be estimated. The effect of inspection depends on the accuracy of the method.

Parts of the risers can also relatively easy be inspected visually above the sea surface and by ROV below sea surface. Inspection of wall thickness can be carried out through ultrasonic measurements.

4 Data and information sources

4.1 Introduction

Various data and information sources and reports have been applied to conclude on the recommended failure frequencies in this report and in related preceding projects. This chapter contains a brief description of the data and information sources. An overview of the data sources included in this chapter is provided in Table 4-1.

A short description of the data and information sources are given in the following sub chapters. Where available information regarding criteria for inclusion / exclusion of data as well as overall failure and exposure data is provided. To the extent available information regarding causes for failure and important factors influencing the failure frequencies are also presented.

Note, the text provided in the following subchapters, describing various data sources, are to a significant extent directly sited from the references provided, even if this is not clearly indicated or stated.

Table 4-1 Overview of the data sources included in this chapter

Data source	Reference	Application	Coverage
NCS – Havtil 2024	/13/, /14/	Offshore Oil and Gas pipelines	Operators on NCS. Data provided by Havtil covering the period 2001-2023.
PARLOC 2020, issued in 2024	/3/	Offshore Oil and Gas pipelines	Operators in UK for the period 2001-2020 (2001-2002 is excluded due to lack of data).
HCRD, UK HSE incident database	/7/	Hydrocarbon pipelines	Hydrocarbon releases within UKCS in the period 1992 to 2015.
CONCAWE report no. 7/24, April 2024	/16/	Onshore oil pipelines	European cross-country oil pipelines throughout the years 1971-2022.
11th EGIG Report, December 2020	/15/	Onshore gas pipelines	Gas transmission system operators in Europe. Incidents recorded during the period from 1970-2019.
UKOPA report issued August 2023	/18/	Onshore oil and gas pipelines	Pipelines on land in the UK, including data for the years 1962 to 2022.
OREDA	/27/	Subsea equipment	Reliability data
PLOFAM	/28/	Subsea equipment	Leak frequency data for process equipment
HIAD	/19/	Hydrogen systems	Incidents and accidents, however without specified inclusion and exclusion criteria.
Vitaly et. al. / PHMSA	/20/	CO_2 pipelines	US CO_2 pipeline incidents up to 2021.
H2Pipe JIP	/21/	H_2 Pipelines	Guideline / code development for transport of hydrogen gas in existing and new offshore pipelines.
SAFEN JIP	/22/	H_2 Pipelines	Data gathering and incident description, for increasing the knowledge on LOC and ignition scenarios.
CO2SafePipe JIP	/23/	CO_2 pipelines	Aiming to close knowledge gaps identified in the transportation of CO_2 in pipelines. Including CO_2 stream composition and its effect on corrosion and materials, and the risk of running ductile fracture.
CO2 Safe and Sour JIP	/24/	CO_2 pipelines	Addressing challenges associated with CO_2 streams including H_2S, and how this may affect the risk for Sulphide Stress Cracking (SSC) and corrosion damages in carbon steel pipelines used for CCS

4.2 Havtil for Norwegian continental shelf

Failure data and population data for offshore oil and gas pipelines and risers on the Norwegian Continental Shelf (NCS), for the period from 2001 through 2023, have been obtained from Havtil (ref. /13/, /14/). NCS data include incidents from infield and transportation pipelines and risers reported to Havtil for this period.

The NCS incidents are categorised either as leak or as damages, i.e. comprises both failures and incidents not resulting in failure. The dataset includes leaks from HC systems, hydraulic system, systems with water, and systems with chemicals. The dataset also includes failures associated with systems that were not in operation.

4.3 PARLOC

PARLOC (Pipeline and Riser Loss of Containment) report revision 7, “PARLOC 2020”, covers pipeline and riser failures on the UK continental shelf for the period 2001 – 2020, and supersedes the previous “PARLOC 2012” report. The main purpose of the report is to present generic data on loss of containment failure frequencies in pipelines and risers that can be used in risk assessments in support of design and operation of offshore oil and gas facilities.

The results presented in the report are based on population data from the North Sea Transition Authority (NSTA database and incident data from HSE and Petroleum Operations Notice 1 (PON 1) reporting systems and is by the Energy Institute regarded as robust.

The PARLOC 2020 report has a more focused scope than earlier PARLOC data reports (ref. /4/, /6/)

- PARLOC 2020 includes hydrocarbon pipelines in normal operations.
- PARLOC 2020 excludes e.g. water and chemical pipelines and failures during one-off operations such as commissioning (this was included in PARLOC 2012).
- The PARLOC 2020 report is based on incident data from the start of 2001 through the end of 2020.

4.4 HCRD

All hydrocarbon leaks within UKCS is collected within the UK HSE Hydrocarbon hDatabase (HCRD), ref. /7/. This contains details of incidents in the UKCS in the period October 1992 to December 2021. HCRD mainly include leaks from topside process equipment, but it also includes details of leaks from risers and. Pipelines.

The failures covered in HCRD is to a large degree overlapping the PARLOC 2020 data, however it covers a longer period and has estimates of hole size available in all cases. HCRD data is thus mainly applied in this study to derive hole size distributions.

4.5 CONCAWE

The 2024 Performance of European cross-country oil pipelines report covers Statistical summary of reported spillages in 2022 and since 1971 (ref. /16/). A total of 68 companies and agencies operating a total of 35,307 km of oil pipelines (1,702 km currently out of service) in Europe are currently listed for the annual CONCAWE survey.

The required criteria for an incident to be recorded by CONCAWE are the following:

- Used for transporting crude oil or petroleum products,
- With a length of 2 km or more in the public domain,

- Running cross-country, including short estuary or river crossings but excluding under-sea pipeline systems. In particular, lines serving offshore crude oil production facilities and offshore tanker loading/discharge facilities are excluded.
- Pump stations, intermediate above-ground installations and intermediate storage facilities are included, but origin and destination terminal facilities and tank farms are excluded.
- The minimum reportable spillage size has been set at 1 m3 (unless exceptional safety or environmental consequences are reported for a <1 m^3 spill).

The total exposure, which expresses the length of a pipeline and its period of operation, is for the period in total 1.4 million km·years. Based on the failures recorded and the total exposure the average failure frequency considering the entire data period is calculated to 5.5E-04 per km-year, including crude, refined products, and hot products. (Note: the failure frequency corresponding to hot product pipelines is above the overall average, while failure frequencies corresponding to crude and refined product pipelines are below the overall average).

The running average failure frequency has increased from 2013 to 2022. The main cause for the increase is theft related spillage incidents. From 2012 to 2017 the five-year moving average increased from approximately 2E-04 to 1.5E-03. In 2022 the five-year moving average is back to the 2012 level.

If excluding theft related failures, the running average has declined steadily since 1975, and in 2022 the running average (excluding theft related failures) was approximately 4E-04. In 2022 the five-year moving average (excluding theft related failures) was approximately 1E-04.

In the most recent decade theft related failures have been the cause for more than 80 % of the spills. Excluding theft, the causes contributing most to the total failure frequency is 3rd party (e.g. i.e. external interference), corrosion and mechanical failure.

The CONCAWE report presents failure frequencies as function of pipe diameter (frequencies decreasing with increased diameter). Although still present, the failure frequency dependency on pipeline diameter does seem to be reduced in the last two decades, as compared with the total data period.

4.6 EGIG

The 11th Report of the European Gas Pipeline Incident Data Group covers the period 1970-2019 (ref. /15/). EGIG is a cooperation of seventeen gas transmission system operators in Europe and it is the owner of an extensive database of pipeline incident data collected since 1970.

The required criteria for an incident to be recorded in the EGIG database are the following:

- The incident must lead to an unintentional gas leak.
- The pipeline must fulfil the following conditions:
    - To be made of steel.
    - To be onshore.
    - To have a Maximum Operating Pressure higher than 15 barg.
    - To be located outside the fence of a gas installation.

The total exposure, which expresses the length of a pipeline and its period of operation, is for the period in total 4.84 million km·years. Based on the incidents recorded and the total exposure the average failure frequency considering the entire data period is calculated to 2.9E-04 per km-year. This is a reduction from 3.3E-04 per km-year when applying a data period from 1970-2013 (as reported in ref. /11/). The failure frequencies have been declining steadily over the period from 1970-2019, and considering only the last five years period the failure frequency is calculated to 1.3E-04.

The distribution of causes to failure frequencies has changed significantly within the 1970-2019 period. In the first two decades external interference contributed to approximately 50 % of the total failure frequency, while corrosion (external and internal) and construction defect / material failure contributed with approximately 15 % each. In the last decade reported (2010-2019) external interference and corrosion contributes with even fractions of approximately 27 % each, while construction defect / material failure and ground movement contribute with approximately 15 % each. (Note: even for causes where the relative fraction has increased, the absolute failure frequency is still reduced.)

The EGIG report presents failure frequencies as function of pipe diameter (frequencies decreasing with increased diameter), depth of cover for buried pipelines (frequencies decreasing with increased depth of cover), pipe wall thickness (frequencies decreasing with increased wall thickness), and year of pipeline construction (frequencies decreasing for more recent constructions). However, for the latter it is uncertain to what degree the higher frequencies for older pipelines can be explained by the design / material selection at the time, and/or the a longer exposure period.

4.7 UKOPA

The latest UKOPA Product Loss Incidents and Faults Report, issued in 2023 (ref. /18/), covers incident data for the period 1962 to 2021. The data presented in the report covers reported incidents where there was an unintentional loss of product from a pipeline within the public domain, and not within a compound or other operational area.

A product loss incident is defined in the context of this report as:

- An unintentional loss of product from the pipeline
- Within the public domain and outside the fences of installations
- Excluding associated equipment (e.g. valves, compressors) or parts other than the pipeline itself

At the end of 2020 the total length of pipelines in operation and corresponding to the scope of the report was 23653 km. The total exposure in the period covered in the failure statistics, 1962 to 2021, was 1.0 million km-years. Based on the failures recorded and the total exposure the average failure frequency considering the entire data period is calculated to 1.97E-04 per km-year. This is a slight decrease from the running average up to 2020 (2.01E-04).

The current five-year and twenty-years moving average failure frequencies are 7.6E-05 and 7.2E-05 per km-year respectively. This is one order of magnitude lower than the running average from the first decade covered, i.e. 1962-1971. Based on the current twenty-years moving average, and the five-years moving average within the last two decades varying between approximately 3.0E-05 and 1E-04, it may seem that the failure frequency has stabilized on this level.

The distribution among various causes of failures as an average over the data period (1962-2021), currently shows that corrosion (mainly external and internal stress corrosion cracking) has contributed to approximately 35 % of the failures, while external interference has contributed approximately 20%. Among failures occurred in the last 5 years external interference, externa corrosion, girth weld defects, and original construction damage has contributed with equal parts, all approximately 10 %. For the latest five-year period the UKOPA report says: "It should be noted that the majority of product loss incidents in recent years have been associated with attachments to the pipeline, rather than failures of the pipe itself.", and are sorted under cause category *Other*. In the lates five-years period fifteen out of sixteen incidents categorized as others are related to welds, clamps, flanges and joints.

The UKOPA report presents failure frequencies as a combined function of selected causes and influencing factors. Some of the combinations are listed below:

- Failures caused by external interference categorized by pipe diameter where the frequencies of failure due to external interference are decreasing with increased diameter.
- Failures caused by external interference categorized by pipe wall thickness where the frequencies of failure due to external interference are decreasing with increased pipe wall thickness.
- Failures caused by external corrosion categorized by pipe wall thickness, where the frequencies of failure due to external corrosion are decreasing with increased pipe wall thickness.
- Failures caused by external corrosion categorized by year of pipeline construction, where the frequencies of failure due to external corrosion are decreasing for more recently constructed pipelines.
- Failures caused by internal stress corrosion cracking categorized by year of pipeline construction, where the frequencies of failure due to internal stress corrosion cracking are decreasing for more recently constructed pipelines.
- Failures caused by girth weld defect categorized by year of pipeline construction, where the frequencies of failure due to girth weld defect is decreasing for more recently constructed pipelines.

Based on the above listed trends it may be concluded that pipeline diameter, wall thickness and year of construction, are all factors which affect the failure frequency.

4.8 OREDA

The Offshore and onshore REliability DAta (OREDA) project was established in 1981 in co-operation with the Norwegian Petroleum Directorate (which has since then changed organization and name to Norwegian Ocean Industry Authority, Havtil). OREDA was sponsored by oil and gas companies with world-wide operations with the main purpose to collect and exchange reliability data among the participating companies (ref./27/).

OREDA has established a comprehensive databank with reliability and maintenance data for exploration and production equipment from a wide variety of geographical areas, installations, equipment types and operating conditions. Offshore topside and subsea equipment are primarily covered (ref. /27/). The databank can currently be accessed online through OREDA@Cloud, a service hosted by DNVs Veracity marketplace platform.

The equipment population that has been considered in the assessment of recommended failure frequencies for subsea equipment includes data collected during the time period 2004-2014. It is assessed that data collected before 2004 to a large degree represents superseded equipment designs and materials that are no longer in used. The data collected are in general from the normal steady-state operating time period (ref. /27/). The systems in the OREDA database are hierarchically organized as:

- Equipment class, where items are grouped based on their main functions
- Equipment unit, which represent each individual item within an Equipment Class
- Subunit, which includes the item required for the Equipment Unit to perform its main function
- Component, which is the subset of each subunit, typically consisting in the lowest level items that are being replaced and repaired as a whole

The subsea database is grouped into 4 main data categories:

- Installation: specifying field name, installation name, geographic location, water depth, etc.

- Inventory: describing each equipment unit and its subunits and components for which data have been collected
- Failure: information about failures recorded for the component during the period of surveillance
- Maintenance: information on corrective maintenance/intervention and its relations to a failure recorded

The failure rate function expresses how likely an item which has survived up to time *t*, will fail during the next unit of time. The failure rate will therefore usually be a function of the *age* of the item. The life of a technical item is split into 3 phases: the burn-in period, the useful life phase, and the wear-out phase. The failure rate function has different shapes during these phases and has an overall “bath-tub” shaped curve, with decreasing rat during “burn-in”, and increasing rate in the “wear-out” phase. Since many of the items covered by the OREDA database are subject to maintenance and replacement, they will be replaced or refurbished before deteriorating (wear-out phase).

Furthermore, the installation problems related to specific items are disregarded during the OREDA data collection, as well as inherent quality problems, which are generally removed by carefully testing the items prior to installation. The burn-in failures are therefore not included in the OREDA database. The main part of the failures recorded in the OREDA database will thus reflect the useful life phase, where the failure rate is assumed (close to) constant.

Assuming a constant failure rate λ defined based on the number of failures and divided by aggregated time in service gives $\lambda = n / t$. The *Mean Time To Failure* (MTTF) during the item useful life can be calculated as $1 / \lambda$.

The following points should be highlighted when using the OREDA model for the scope of this report:

- The figures in the handbook reflect a weighted average of the failure (and maintenance) data
- No statistical tests have been performed to verify the assumption of a constant failure rate for the items in the OREDA database

4.9 PLOFAM

PLOFAM (Process Leak for Offshore installations Frequency Assessment Model, ref. /28/) is designed to be a tool for estimation of leak frequencies for use in quantitative risk assessment (QRA). The model is designed to estimate leaks with leak rate exceeding 0.1 kg/s and represents what is currently considered the latest statistical leak frequency data for modern topside equipment.

The model has considered historical data covering the Norwegian Continental Shelf (NCS) and the United Kingdom Continental Shelf (UKCS). The parametrization of the PLOFAM model and its validation is mainly based on the data from the NCS, which quality is regarded as high (ref. /28/). The model validation shows that the PLOFAM model can reproduce the total number of leaks on the NCS in the period 2006-2017 and the total cumulative leak rate frequency distribution given by the historical data in the period 2001-2017 (ref. /28/). Furthermore, PLOFAM is tuned to give the same number of leaks with a leak rate higher than 0.1 kg/s as observed in historical data for the NCS in the period 2006-2017. The topside data from UKCS shows similar hole size frequency distribution, time trends and total leak frequency. The PLOFAM model is therefore concluded valid both for NCS and UKCS. A total of 254 incidents were recorded on all the installation located on the NCS in the period from 2001 to 2017. For comparison 4561 leaks were recorded on the UKCS for the period 1992-2005 (ref. /28/).

The PLOFAM model covers a large range of equipment types for which base frequencies for topside leaks are provided. The base frequency represents leaks corresponding to hole sizes larger than 1mm. the model only include failures resulting in hydrocarbon leak. The model assumes that the total leak frequency for a system is proportional to the number of each type of equipment based on statistics per equipment, hence that all leaks are independent. For some equipment the model is equipment size dependent.

4.10 HIAD

The Hydrogen Incidents and Accidents Database (HIAD) is an international open communication platform collecting systematic data on hydrogen-related undesired incidents (ref. /19/). HIAD was initially developed in the frame of HySafe by the Joint Research Centre (JRC) of the European Commission. It was updated by JRC as HIAD 2.0 in 2016 with the support of the *Fuel Cells and Hydrogen 2 Joint Undertaking* (FCH 2 JU). The European Hydrogen Safety Panel (EHSP) has worked closely with JRC to upload additional/new incidents to HIAD 2.0, and new incidents are continuously being uploaded. The latest public available extract of data from HIAD, dated January 1st, 2024, includes 755 incidents and accidents.

HIAD includes a wide variety of incidents associated with hydrogen equipment and leaks. The vast majority of the incidents are not associated with transport pipeline systems. A search for the word “pipeline” in the data extract file returned 49 incidents and accidents. Most of these incidents and accidents are however associated with process piping on refineries, various plants (metallurgical, de-sulphuration, chlorine electrolysis, methanation, etc.) and hydrogen fuel stations.

A total of 12 incidents and accidents were judged to be relevant for hydrogen transport pipeline systems. These include pipeline weld failures, blind flange, seal, and flow meter failure. The causes registered include excavation and agricultural drainage works, corrosion, erosion and soil settling, lightning strike, and hydrogen induced cracking in heat affected zones.

Another challenge with the data extracted from HIAD is that it is difficult to associate a population of pipelines and other hydrogen systems and equipment matching the inclusion / exclusion criteria applied for incidents included in the database. The database is also not based on a mandatory reporting scheme. The database thus does not provide failure frequencies in terms of pipeline km-years, equipment-years, or any other exposure category.

The purpose of HIAD is thus not to provide a basis for failure frequencies, but to provide knowledge associated with hydrogen incidents and accidents and certainly do provide valuable lessons learned which can be applied in risk management.

4.11 PHMSA – CO_2 pipelines

The US Pipeline and Hazardous Material Safety Administration collects incident records for pipelines in the United States transporting hazardous material. This includes failure incidents associated with CO_2 pipelines. The most relevant identified compilation of CO_2 pipeline incidents is an article by Vitali et.al. (ref. /20/) which provides a statistical analysis of incidents on onshore CO_2 pipelines based on the PHMSA database. The article by Vitali et.al. focused on analyzing the PHMSA incident data related to CO_2 pipelines operating in the US from 1994 to 2021. Onshore CO_2 pipelines have been installed in the U.S. mostly for enhanced oil recovery (EOR) applications.

Incidents corresponding to either of the following criteria should be reported to PHMSA:

- involve fatalities or injuries requiring in-patient hospitalizations,
- have $ 50,000 or more in total costs (including loss to the operators or the others, but excluding cost of gas lost),
- results in release of 50 barrels or more of product,
- result in an unintentional fire or explosion.

4.12 H2Pipe JIP

H2Pipe in a Joint Industry Project lead by DNV and addressing transportation of hydrogen gas in offshore pipelines (ref. /21/). This is a joint industry project to develop the world's first guideline for transport of hydrogen gas in existing and new offshore pipelines.

To provide cost-efficient hydrogen delivery it is essential to more accurate, reliable, and possibly less conservative code requirements, and to also have a better understanding of the real design limitations. The JIP aims to enhance the general understanding on how hydrogen gas affects the material properties (both as 100% H_2 and a blend with natural gas) and further the real design limitations, and to provide a better understanding on how a pipeline system can be designed for safe hydrogen gas transportation, and if necessary, which mitigation measures that should be put in place.

The aim for the new pipeline code, for design, construction and operation of offshore pipelines transporting hydrogen is however to provide a pipeline safety target level equivalent to that of e.g. offshore pipelines transporting hydrocarbon. Although not contributing with failure data as such, the expectation is that through application of the new pipeline code, the failure frequencies (or pipeline safety target level) shall become comparable to failure frequencies established for e.g. hydrocarbon pipelines.

4.13 SAFEN JIP

Safen is a Joint Industry Project lead by Safetec and consists of 21 industry partners, including DNV (ref. /22/). The JIP objectives include establishing knowledge required to develop risk-based methodologies enabling cost-efficient safety design across the renewable sector involving hydrogen, ammonia, and CO_2. Safen JIP includes gathering data supporting the development of loss of containment and ignition probability models for hydrogen systems. In addition to covering processing equipment, storage tanks and vessels, loading/offloading facilities, Safen also aims at proposing a leak model for transport pipelines. The Safen phase 2 work aim at completing by year end 2025.

4.14 CO2SafePipe JIP

CO2SafePipe is a Joint Industry Projects lead by DNV (ref. /23/). CO2SafePipe is addressing knowledge gaps in the transportation of CO_2 in pipelines, aiming to close such knowledge gaps identified in the transportation of CO_2 in pipelines covering CO_2 in both gas phase and dense phase, CO_2 stream composition and its effect on corrosion and materials, and the risk of running ductile fracture. This JIP identifies benefits and disadvantages of transporting CO_2 in gas phase compared to dense phase, and how the phase chosen impacts the design or re-qualification process for existing CO_2 pipelines.

4.15 CO2 Safe & Sour JIP

CO_2 Safe & Sour is a Joint Industry Projects lead by DNV (ref. /24/). CO_2 Safe and Sour is addressing challenges associated with CO_2 streams including H_2S, and how increasing acceptable levels of H_2S will affect the risk for Sulphide Stress Cracking (SSC) and corrosion damages in carbon steel pipelines used for CCS.

Future CO_2 pipelines are expected to transport CO_2 produced by a wide variety of processes, and the stream quality in terms of different impurities as well as the amount of the various impurities may vary significantly. The effect of impurities in CO_2 streams are also addressed by Sonke et.al. (ref. /25/).

5 Recommended failure frequencies

5.1 Introduction

This chapter presents models for estimation of failure frequency for various pipelines and risers. The main principle is to present recommended failure data on different segments of a pipeline. Thus, assessment of specific pipeline is done by combining frequencies from relevant segments. Figure 5-1 shows how a pipeline is divided into several segments.

The sub models used to assess different pipeline segments varies. For some segments it is recommended to use a distance dependant model. Other segments require additional factors in order to reflect individual conditions. Some segments consist of a combination of both.

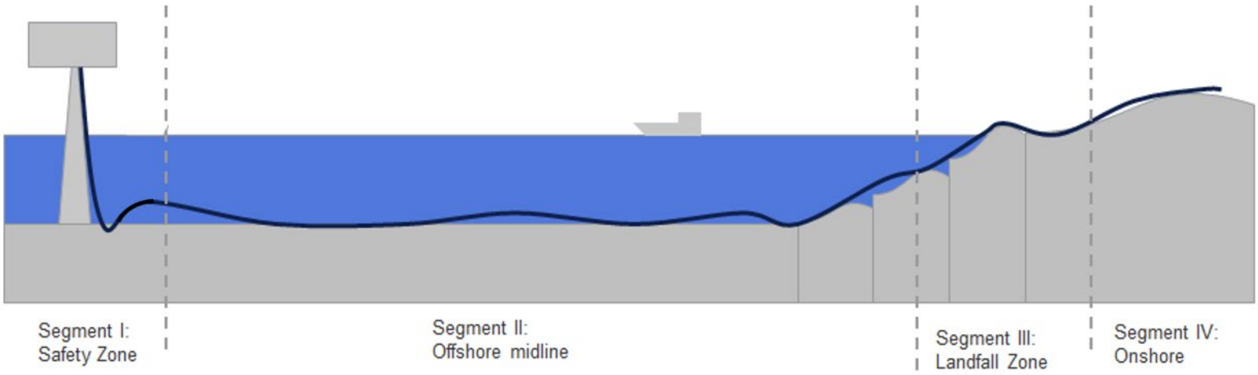

Figure 5-1 Main model of pipelines, segment division

- Segment I: Safety zone. The safety zone consists of the platform (installation) and a predefined surrounding area (normally within 500 m of the installation).
- Segment II: Offshore midline. The midline is located between the safety zone and the landfall zone (or between safety zones).
- Segment III: Landfall zone. The landfall zone consists of pipelines in coastal zone.
- Segment IV: Onshore.

Offshore HC pipelines (segment I and II) are described in chapter 5.2. Onshore HC pipelines (Segment IV) are described in chapter 5.3. HC Risers (Segment 1) are described in chapter 5.2.2 and jumpers in chapter 5.2.3. Unless more specific data is available, onshore data are recommended to be used for the landfall Zone (segment III). For the safety zone it is recommended to do a separate study to include dropped objects and ship collision (external damage). Failure frequencies for subsea HC equipment are given in chapter 5.2.7.

Failure frequencies for CO_2 pipelines and H_2 pipelines are treated in chapters 5.3.4.7 and 5.5 respectively. In this edition of the report a recommended failure frequencies for isolation joints are also included, presented in chapter 5.6.

When estimating the failure frequency for a specific pipeline, all available information on that pipeline (such as operational experience, inspection results etc.) should be considered. Pipeline expertise should be involved to judge how different loads or defects may affect the integrity of the pipeline. The failure frequency model developed for offshore transport pipelines, the score grade model presented in chapter 5.2.6, includes such assessments.

More details regarding pipeline manufacturing methods and causal relations for pipeline failures are included in appendices A and B. Detailed model for estimating offshore pipeline failure frequencies associated with dragged anchors and ship foundering are presented in Appendix C and D.

5.2 Pipelines, risers and equipment in hydrocarbon service offshore

5.2.1 Data sources

The estimated failure frequencies for offshore HC risers and pipelines are based on the PARLOC 2020 report (ref. /3/) covering incidents on the UKCS from 2001-2020[9] and failure data from NCS covering the period 2001-2023 (ref. /13/, /14/). The frequencies given are applicable for normal operations. Construction and testing phases are excluded and risk related to such phases much be evaluated separately.

Leaks associated with valves, flanges, PLEM pig traps failures are in general not included in the failure frequency estimates. Such failures must be included separately as part of an installation risk analysis. *The flanges connecting risers, jumpers and pipelines are however included in the base frequency.*

Furthermore, failure frequency contribution from external loads, such as ship collision and dropped objects, both from lifting operations and dropped / dragged anchors, are not included in the estimated failure frequencies and must be added if assessed relevant.

For NCS 63 failures, LOC from HC pipelines, risers and jumpers, were registered in the period 2001-2023. 28 of these failures are included in the basis for the estimated recommended failure frequency for riser/jumper and pipeline body. The remaining failures were related to equipment and intermediate phases and are thus excluded from the frequency analysis.

5.2.1.1 Pipelines on UK continental shelf

PARLOC (Pipeline and Riser Loss of Containment) report revision 7, in the following referred to as “PARLOC 2020”, covers pipeline and riser failures on the UK continental shelf for the period 2001 – 2020. PARLOC 2020 supersedes the previous PARLOC 2012 report. With respect to the scope and frequencies presented in PARLOC 2020, the following should be mentioned:

- Failures outside of the riser emergency shutdown valve (ESDV) are included, while failures in the pipeline system on the platform side of the riser ESDV are excluded.
- The scope of PARLOC 2020 included the years 2001 – 2020. However, there were no failures recorded in 2001 and 2002. These two years are thus excluded from the incident dataset and from the population data.
- Trunk pipelines from other countries (notably Norway) were excluded from the analysis. No failures were recorded for these pipelines and excluding the population data associated with such pipelines is thus conservative.
- Population data for fittings on pipelines is not covered in PARLOC 2020. However, the dataset does include failure of fittings (e.g. block and bleed valve, a flange joint between a jumper and a spool). The likelihood of these failures is assessed to be dependent on the number of fittings and equipment attached to the pipeline. Since a specific failure frequency for fittings cannot be calculated, failures associated with fittings are assigned to the pipeline that the fitting is attached to.
- Three failures were recorded on fittings attached to pipeline manifolds. For these manifolds more than one pipeline is attached. As these failures cannot be associated with a particular pipeline, they have not been included in the frequency analysis.
- Incidents relating to infrequent specific operations have been excluded.
- Failure frequency inside and outside the safety zone are given separately.

9 Due to lack of data, the PARLOC 2020 report does not include data for 2001 and 2002

- Separate frequencies are given for jumpers. Their population is recorded separately, and the following definition for a jumper is used:
    - All pipelines with a length of 200 m or less
    - Pipelines up to a length of 500 m if labelled as a "jumper" or a "spool" in the NSTA database

PARLOC 2020 states that the data on hole sizes for the failures is incomplete. Of a total of 56 registered failures, there is no information given for 12 failures, while 10 failures are only known not to be full ruptures or to be very small.

PARLOC 2020 does not provide pipeline failure frequencies categorized by pipeline diameter or content, but separate failure frequencies are given for different pipeline length categories. PARLOC 2020 states *"Pipeline length is a proxy for a numerous of other factors that effects the LOC frequency".*

The failure frequency estimated for jumpers is based on 18 failures. Failure frequencies for the various length categories for pipelines, or leak location categories for risers, are based on between 2 and 7 failures each. The confidence interval for the failure frequencies is therefore significant.

5.2.1.2 Pipelines on Norwegian continental shelf

Failure data for offshore oil and gas pipelines on the Norwegian Continental Shelf (NCS) have been applied to supplement the PARLOC 2020 dataset.

The NCS data obtained from Havtil in 2024 (ref. /13/ and /14/) is covering the period 2001-2023 and is in the following referred to as "NCS 2024". In total 433 incidents are recorded for this period. All incidents have been categorised either as damages or as leaks. 295 incidents are categorised as damages while 138 incidents are registered as a leak, i.e. failures). 63 failures are related to HC systems on live systems. 53 failures were related to hydraulic systems, 16 failures were related to systems with water or other chemicals, and 4 failures were related to systems that were shut down.

For NCS 2024, the inclusion and exclusion criteria applied corresponds to those applied for PARLOC 2020. Applying these criteria, the number of failures used as basis for further failure frequency analysis is 28, presented in Figure 5-2. The other 35 failures were excluded based on the following:

- In total 30 failures associated with subsea equipment, wells, loading/unloading arms, topside process, and onshore pipelines and equipment were excluded. Such failures are subjected to separate assessments and counting in a QRA.
- 3 failures registered as steel pipeline failures are excluded as they were found to be related to flanges and not the pipeline itself.
- 1 failure registered as a flexible pipeline failure was excluded as it was defined as insignificant with regards to size and content. The failure was assigned to a vent and thus assessed not relevant for the pipeline failure frequency analysis.
- 1 failure caused by anchor drop was excluded as such failures are subjected to separate analysis, and thus not covered in the generic pipeline failure frequency analysis.

Most of the recorded failures in NCS 2024 are associated with small leak rates and or leaked volumes. For many failures the leak rate, hole size, and/or leak volume is not specified, while the description often indicates a small leak rate or hole size.

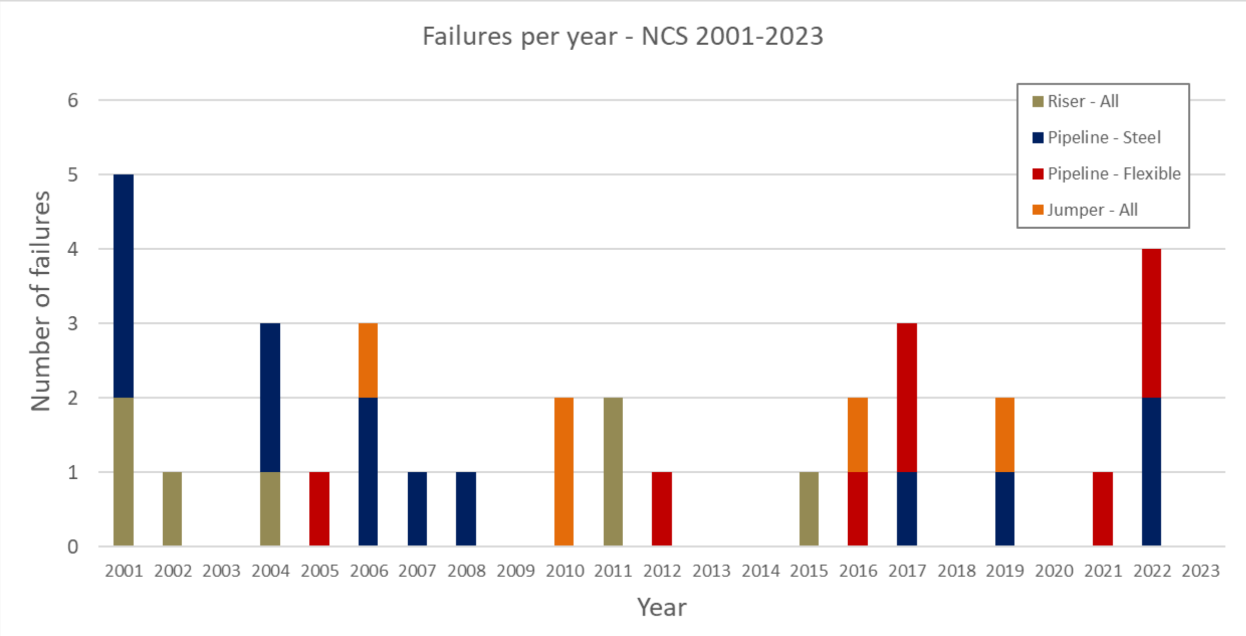

Figure 5-2 Failures registered on the NCS (NCS 2024, ref /13/, /14/) used in the failure frequency analysis.

For several failures associated with flexible pipelines or flexible risers the description indicates a hole in the outer sheet. It is unclear whether this is a leak of the actual pipe inventory or hydrocarbons trapped in the annulus that contributes to the leak. Half of the flexible riser failures (3 out of 6) are carcass collapse resulting in external leak.

Even though most of the failures registered for flexible riser failures are small, it is worth noting that a relevant failure recorded during the last 5 years seems to be rupture of a flexible riser. The riser was not in operation at the time of the failure and had been operated as a water injection riser. Hence, this failure has not contributed to the estimated HC failure frequency for risers. Based on the description it seems degradation of the armour layer was contributing to the failure of the riser, and given that the riser was a WAG riser, it gives a strong indication that the potential for rupture of flexible hydrocarbon risers cannot be disregarded.

Given that riser rupture seems to be plausible during hydrocarbon service, it can be argued that estimated rupture frequency of flexible risers based on the model should not be considered overly conservative.

Pipelines defined as decommissioned or abandoned has been excluded from the population data from the date where this classification is given. For risers defined as decommissioned, however where no decommissioned date is given, the decommissioning date is set to 31st of December 2012.

5.2.2 Risers

5.2.2.1 Failure and population data

Riser failure frequencies are estimated for both flexible risers and steel risers transporting gas, oil, multiphase fluid and condensate. The frequencies are estimated based on failure data and population data from PARLOC 2020 and NCS 2024.

Combined failure and population data from these two sources are hereafter referred to as “DNV 2025”. DNV 2025 data and recommended failure frequencies are presented in Table 5-1. Table 5-1 also include the data used in the 2017 edition of this report (referred to as “DNV 2017”).

Incidents with valves, flanges and pig traps are not included in the numbers presented in Table 5-1 since these are normally counted separately in risk assessments. It should however be noted that the flange between a riser and a pipeline / jumper are included.

Table 5-1 Summary of riser failure and population data

	DNV 2017	DNV 2025
Exposure, flexible risers [riser years]	10129	4667
Exposure, steel risers [riser years]	24750	12824
Number of failures, flexible risers	37	10
Number of failures, Steel risers	19	7

5.2.2.2 Riser failure frequencies categorised by riser diameter

For flexible risers, the previous version of this report did not distinguish failure frequencies by riser diameter. For steel risers, the previous version distinguishes failure frequencies between riser diameter up to (≤) 16” and above (>) 16“.

NCS has recorded only 32 riser years for flexible risers with diameter > 16”. The flexible riser diameter categories in PARLOC comes in 2” intervals up to 8”, with the final category for diameters > 8”. It is therefore assessed not reasonable to provide separate failure frequencies for flexible risers with diameter > 16”.

As stated in chapter 3.4.6, there are several sources pointing out that the failure frequencies for steel risers and pipelines decrease with increasing diameter. The data underlining this fact originate from different geographical locations and for both gas and oil pipelines.

PARLOC 2020 does not distinguish between riser diameter for neither flexible nor steel risers, arguing the statistical basis for doing this is regarded as weak. Even though PARLOC 2020 does not estimate separate failure frequencies for risers with diameter > 16”, there is population data for steel risers with diameter > 16”. Combining PARLOC 2020 failure data and population data for steel risers shows a declining trend for riser diameter categories, up to 6”, 6” to 10”, 10” to 16”, and further no failures for risers with diameter exceeding 16”.

While there is no recorded failures recorded in PARLOC 2020 nor NCS 2024 for steel risers with diameter > 16”, the total number of riser years for steel riser with diameter > 16”, for PARLOC 2020 and NCS 2024 combined, is 4244. It is thus assessed reasonable to recommend separate failure frequencies for steel risers based on riser diameter, and to keep the riser diameter categories applied in previous editions of this report, i.e. up to 16” and above 16”.

For steel risers, the following approach has been used:

- Diameter ≤ 16”: The recommended failure frequency is based on the combined number of failures and population data from PARLOC 2020 and NCS 2024.
- Diameter > 16”: The recommended failure frequency is based on 0.7 failures[10] and the combined population data from PARLOC 2020 and NCS 2024.

The recommended failure frequencies for risers are given in Table 5-2.

[10] In a Poisson distribution 0.7 incidents represents a probability of 50% for having 0 incidents. To reflect the uncertainty in the estimates this is therefore used as basis as no incidents are recorded.

Table 5-2 Calculated diameter dependant riser frequencies

Riser type	Recommended failure frequency 2025	Recommended failure frequency 2017	Units	Change vs. 2017
Steel risers ≤ 16”	8.2 E-04	1.0 E-03	riser year	- 18 %
Steel risers > 16”	1.1 E-04 *	1.1 E-04 *	riser year	Negl.
Flexible risers	2.1 E-03	3.7 E-03	riser year	- 43 %

** Note: There are no known failures associated with steel risers with diameter > 16”. In a Poisson distribution 0.7 incidents represents a probability of 50% for having zero incidents. Combining this with the population data PARLOC 2020 and NCS 2024 for steel risers with diameter > 16”, the estimated failure frequency becomes 1.7E-4. In the previous edition of this report the same approach was made, as there were no such failures registered for steel risers with diameter > 16” in the PARLOC 2001, PARLOC 2012 and NCS 2017 datasets either.*

However, the population data in the PARLOC 2001, PARLOC 2012 and NCS 2017 datasets corresponding to steel risers with diameter > 16” was larger than the populations included for this rise category in PARLOC 2020 and NCS 2024. Consequently, the estimated failure frequency is increasing when using the new datasets, despite that no such failures have been observed.

As it seems non-intuitive that an increased data range with, however still no failures recorded, shall result in an increased failure frequency. It is therefore suggested to keep the frequency from the previous report, 1.1E-04.

5.2.2.3 Riser failure frequencies per leak location

Three riser leak locations have been specified in previous editions of this report; Subsea, splash zone, and above water. In the PARLOC 2020 and NCS 2024 data reviewed no riser leaks are specified for the splash zone. The lack of registration of leaks in the splash zone may however be a result of how incidents are reported. Often the leak location is not specified directly, while in some cases it can be assumed based on incident description.

In the previous edition of this report, DNV 2017, a distribution was used based on PARLOC 2001 and PARLOC 2012 data. Historically, the splash zone has been regarded as a critical area with regards to failure caused by corrosion. Also considering the limited number of riser failures recorded it is assessed that excluding the splash zone as a potential leak location is not a robust approach.

Both PARLOC 2020 and NCS 2024 have a significantly different split between steel and flexible risers with regards to failures recorded above and below water. For steel riser all failures on the NCS are recorded to be above water, while almost 70 % of the failures on the UKCS are recorded to be above water. For flexible risers all failures on the NCS are recorded to be subsea, while more than 70 % of the failures on the UKCS are recorded to be subsea.

For modelling purposes, three typical configurations are shown in Figure 5-3.

- Configuration 1: Riser with connected jumper SSIV and pipeline
- Configuration 2: Riser with connected pipeline
- Configuration 3: Flexible riser with J-tube and Lazy-S connected to jumper SSIV and pipeline

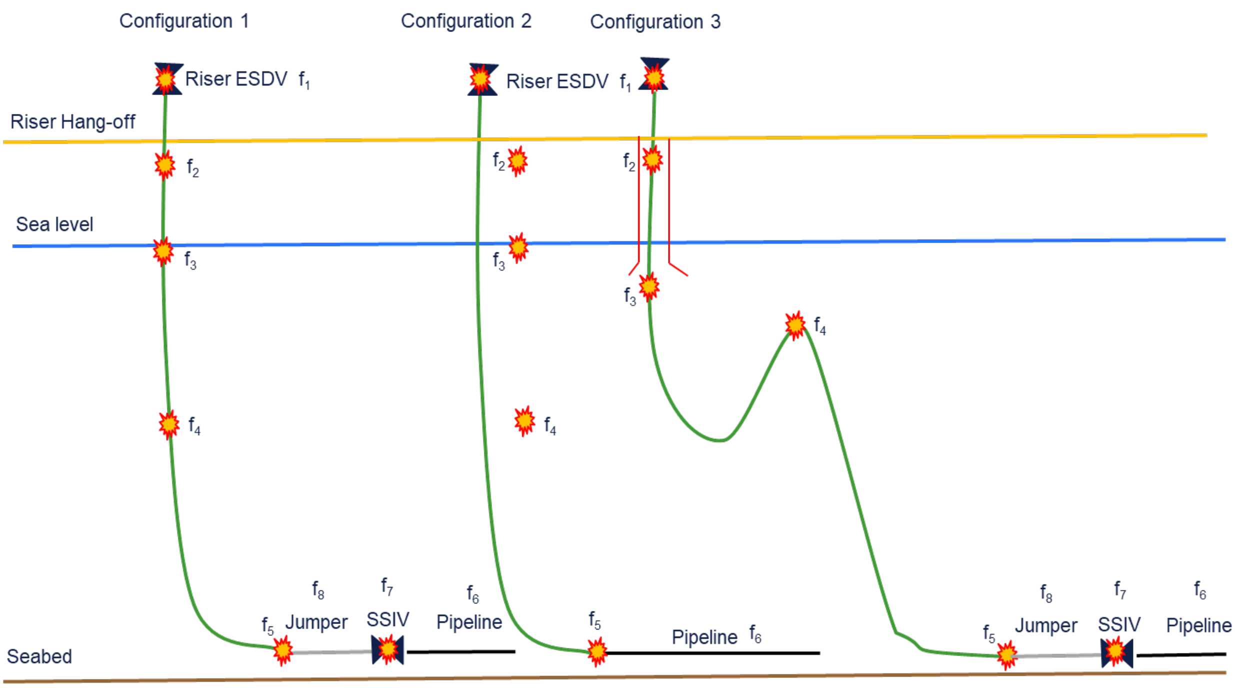

Figure 5-3 Riser leak location distribution from PARLOC2020 and NCS2024

The following guidance applies:

- Topside ESDV failure frequency f_1: The failure frequency for this valve shall be taken from topside process statistics and added to the calculated riser frequency.
- Riser failure frequencies $f_{2\text{-}5}$: The distribution in Table 5-3 shall be used together with the calculated riser failure frequency.
- Pipeline failure frequency f_6: The failure frequency for pipelines shall be calculated separately (see chapter 5.2).
- SSIV failure frequency f_7: The SSIV failure frequency together with related instruments and flanges shall be calculated separately based on subsea equipment statistics (see chapter 5.2.5).
- Jumper failure frequency f_8: The failure frequency for jumpers shall be calculated separately based on (see chapter 5.2.3).
- If the riser is guided through a J-tube, an assessment must be made with respect to whether the leak will be released through to top sealing or through the bell mouth.
- The leak locations shown in Figure 5-3 and Table 5-3 may be combined if relevant.

Table 5-3 Leak location distribution for riser leaks

Location	factor	Steel risers	Flexible risers
Above water	f_2	35%	10%
Splash zone	f_3	35%	30%
Midway in water column	f_4	15%	30%
Subsea at Riser base	f_5	15%	30%

5.2.3 Jumpers

In the PARLOC 2020 database, all pipelines less than 200 m has been defined as jumpers. In addition, all pipelines tagged as jumper or spool, with a length less than 500 m has been defined as jumpers. A corresponding definition has been applied for the NCS 2024 data.

A total of 23 failures has been identified within the two datasets. The corresponding recorded population is 4883 jumper years. Within the UKCS 2020 data there is an overweight of failures on flexible jumpers (approximately 60 %) compared with steel jumpers, while for the NCS 2024 data the material is unknown for most of the failures. Within the combined population data for PARLOC 2020 and NCS 2024 there is also a an overweight of flexible jumpers (approximately 55 %) compared with steel jumpers.

The recommended failure frequency for jumpers is thus estimated based on the combined failures and population from PARLOC 2020 and NCS 2024 and combining both steel and flexible jumpers. This frequency, 4.7E-03 per jumper-year, is assessed representative for both steel and flexible jumpers.

5.2.4 Pipelines

5.2.4.1 Failure and population data

The basis for the PARLOC 2020 and NCS 2024 are described in chapter 5.2.1.1 and 5.2.1.2. It should be emphasised that the criteria for including failures have changed in PARLOC 2020 compared with previous editions of PARLOC (2012 and 2001). PARLOC 2020 includes failures related to the pipeline body only. Failures related to components and equipment such as SSIVs and pig receivers are excluded from the data set. The failure frequency contribution from such equipment should however be calculated separately. Failures associated with dragged anchor should also be calculated separately, and failures known to be caused by this (one event in NCS 2024) is thus excluded from the failure data set.

The combined number of failures included in the failure frequency analysis, from PARLOC 2020 and NCS 2024, is 41. 16 failures are related to flexible pipelines and 25 failures are related to steel pipelines. A summary of the combined failure data and population data are given on Table 5-4. Table 5-4 also include data from the previous report edition for comparison.

Table 5-4 Summary of pipelines data included in the DNV 2025 dataset compared with the dataset included in the previous edition of this report, DNV 2017.

	DNV 2017	DNV 2025
Flexible pipelines [km years]	14206	14268
Steel pipeline [km years]	667363	497514
Flexible pipelines – failures	31.7	16
Steel pipelines – failures	64.5	25

Pipeline material

Previously statistics have shown a significant difference in failure frequencies between steel and flexible pipelines. While the failure frequencies for both steel and flexible pipelines have been reduced by almost 50 %, the statistics shows that the failure frequency per pipeline km-year is still significantly higher for flexible pipelines compared with steel pipelines.

Leak location inside vs. outside facility safety zone

PARLOC 2020 distinguishes between pipeline failures insider and outside the safety zone of an offshore facility. NCS 2024 data have been sorted accordingly. From the combined dataset, 22% of the failures are registered to have occurred inside the safety zone. The distribution is fairly similar for both steel and flexible pipelines.

Considering most pipelines are significantly longer than the 500 m inside the safety zone, the failure frequency per length unit is significantly higher inside the safety zone. This is despite failures from jumpers and failures caused by external loads have been excluded from the failure frequency analysis.

Pipeline diameter

Experience shows that pipelines with a large diameter have fewer pipeline failures per unit length than pipelines with smaller diameter. For the flexible pipelines covered by PARLOC 2020 and NCS 2024, there are no known failures associated with pipelines with diameter exceeding 16”. For the PARLOC 2020 data all but two failures are however known to be associated with pipelines with diameter ≤ 8”, while for the NCS 2024 dataset all but two failures are known to be associated with pipelines with diameter ≤ 10”. The diameter of the pipelines associated with the remaining four failures are unknown.

For the failure associated with steel pipelines included in PARLOC 2020, twelve are known to be associated with pipelines with diameter ≤ 16”. The remaining four failures are associated with pipelines with diameter > 16”, the actual diameter is however not specified. For these four failures two are known to be within the facility safety zone. The remaining two failures associated with steel pipelines with diameter > 16”, with leak location outside the safety zone, one is associated with a short pipeline (3 – 10 km), and one is associated with a medium length pipeline (30 -100 km).

For the failure associated with steel pipelines included in NCS 2024, seven are known to be associated with pipelines with diameter ≤ 20”. For the remaining two failures associated with steel pipelines included in NCS 2024 the pipeline diameter is unknown. These two failures are however known to be associated with pipelines transporting unprocessed fluid. There is no failures associated with steel pipelines transporting processed fluid, which have diameter exceeding 24”.

Fluid type and pipeline length

In previous editions of this report, the failure frequencies estimated has also shown significant differences when categorising pipelines based on fluid type transported. The distinction between fluid type has previously only been made for steel pipelines. Flexible pipelines are often used in-field, i.e. connecting subsea templates with manifolds or production or gas injection risers.

For the NCS 2024 data the fluid type, pipeline material, and pipeline diameter, are mostly provided (sometimes one or more of these attributes are however not specified). PARLOC 2020 do however no distinguish between fluid type. Instead, PARLOC 2020 presents failures and population data, for steel pipelines, categorised by pipeline length, stating that *“Pipeline length is a proxy for a numerous of other factors that affect LOC frequency, e.g. diameter and wall thickness. The longer pipelines are typically large diameter dry gas or stabilized crude/condensate transmission pipelines whereas the shorter pipelines are mainly smaller diameter carrying corrosive unprocessed well fluids”.*

The pipeline failure frequency presented in PARLOC 2020 for steel pipelines with length up to 10 km are also found to be remarkably similar to the failure frequencies estimated for steel pipelines on the NCS transporting unprocessed fluids. Combining these two populations the estimated failure frequency is 4.3E-04. The failure frequencies established based on failures within each of the two populations are less than 10 % different from the combined failure frequency. Thus, these two datasets seem to represent comparable pipeline populations.

The pipeline failure frequency calculated for PARLOC 2020 steel pipelines between 10 km and 100 km, and NCS 2024 steel pipelines with diameter ≤ 24” transporting processed fluid, are thus found to be comparable. Combining these two populations the estimated failure frequency is 3.9E-05. Again, the failure frequencies established based on failures within each of the two populations are less than 10 % different from the combined failure frequency. Thus, these two datasets seem to represent comparable pipeline populations.

For steel pipelines covered in PARLOC 2020 with length exceeding 100 km, and for steel pipelines in the NCS 2024 dataset with diameter exceeding 24” and transporting processed fluid, there are no registered failures.

The above review of PARLOC 2020 data for steel pipelines categorised by pipeline length and NCS 2024 data for steel pipelines categorised by diameter and type of fluid transported, indicates that the categories as discussed seem to cover comparable pipeline populations. It should be noted however that the effect of categorising PARLOC 2020 data according to the pipeline diameter and fluid type categories as indicated above will have a significant effect on the failure frequency calculated for e.g. for a steel gas lift pipeline with length up to 10 km. If categorised as a pipeline with diameter ≤ 24” transporting processed fluid the assigned recommended frequency will be one order of magnitude lower than what is suggested in PARLOC 2020 for steel pipelines with length ≤ 10km. The opposite will be the case for an in-field steel pipeline with length between 10 and 100 km, transporting well fluid. Nevertheless, it is assessed that the pipeline failure frequency is likely to be more influenced by transported fluid than by pipeline length.

Pipeline categorisation

In this study the categories used for steel pipelines in previous editions of this report is kept unchanged except from also differentiating between leak location inside or outside the facility safety zone. Failure frequencies are in this edition thus established for the following pipeline categories:

- Steel pipelines inside safety zone.
- Steel pipelines outside safety zone transporting unprocessed fluid, including data from PARLOC 2020 for steel pipelines with pipeline length up to 10 km.
- Steel pipelines outside safety zone transporting processed fluid, with diameter ⩽ 24”, including data from PARLOC 2020 for steel pipelines with pipeline length between 10 km and 100 km.
- Steel pipelines outside safety zone transporting processed fluid, with diameter > 24”, including data from PARLOC 2020 for steel pipelines with pipeline length exceeding 100 km.
- Flexible pipelines inside the safety zone.
- Flexible pipelines outside the safety zone.

5.2.4.2 Pipelines inside safety zone

Flexible pipelines

Combining the failure data in the PARLOC 2020 and NCS 2024 datasets for flexible pipelines inside the safety zone with the associated population data a failure frequency of 6.0E-04 per pipeline-year is estimated.

Steel pipelines

Combining the failure data in the PARLOC 2020 and NCS 2024 datasets for steel pipelines inside the safety zone with the associated population data a failure frequency of 4.0E-04 per pipeline-year is estimated.

Difference between PARLOC 2020 and NCS 2024 data

The failure frequencies estimated by NCS 2024 data alone would result in failure frequencies approximately 20 % of the corresponding failure frequencies estimated based on PARLOC 2020 data alone. This is the case for both flexible and steel pipelines inside the safety zone.

Failures associated with e.g. valves, flanges, PLEM pig traps etc. are in general not included in the failure data used to estimates pipeline failure frequencies. For NCS 2024 flanges connecting risers, jumpers and pipelines are however included in the data used as basis for frequency estimates, while failures related to other equipment, components and connections are excluded. PARLOC 2020 does however include failures associated with e.g. block and bleed valves. The fraction of failures related to such equipment in PARLOC 2020 is not known. The difference in failure frequency between PARLOC 2020 and NCS 2024 data may to some extent be explained by somewhat different criteria for including attached equipment.

Due to a low number of failures in each dataset, the uncertainty associated with the failure frequencies estimated based on each dataset alone is considered higher than the failure frequency estimated based on the combined data. The failure frequencies established based on the combined PARLOC 2020 and NCS 2024 datasets are assessed more robust and are thus the recommended failure frequencies to be applied for pipelines inside the safety zone.

5.2.4.3 Flexible pipelines outside the safety zone

For flexible pipelines there has not been distinguished between fluid type and diameter. Most flexible pipelines are assumed to have a pipeline diameter ⩽ 16”, and transport fluid over relatively short distances between subsea templates, manifolds and installations. The fluid transported is often well fluid but may also be processed gas for gas injection and gas lift purposes. For flexible pipelines fluid type may not have the same influence on failure frequency as it does for steel pipelines, i.e. where the more corrosive unprocessed is known to affects the steel.

The failure frequency for flexible pipelines is estimated by the total number of failures and the total pipeline population for flexible pipelines for PARLOC 2020 and NCS 2024 combined. The recommended failure frequency for flexible pipelines is 1.0E-03 per pipeline km-years.

5.2.4.4 Steel pipelines outside the safety zone transporting unprocessed fluid

Pipelines transporting unprocessed fluid, are assessed mainly to constitute relatively short in-field pipelines, mostly up to 10 km and rarely exceeding 30 km. These pipelines are transporting fluids between subsea templates, manifolds and installations. Pipelines that are transporting processed fluids are often, but not always, significantly longer than 10 km. This is supported by the review and comparison of NCS 2024 data categorized by transported fluid and pipeline diameter, and PARLOC 2020 data categorized by pipeline length.

Some failure mechanisms found to be relevant for this pipeline category are assessed to have a low dependence on pipeline length. This includes the potential for internal corrosion caused by water and impurities in the well stream which in combination with certain pressure and temperature conditions may result in corrosive conditions (ref. discussion in section 3.4.1). A “critical zone” where corrosive conditions occur is assessed to depend on factors such as fluid content, water cut, pressure, reservoir temperature and fluid temperature gradient within the pipeline, and may thus vary significantly between well fluid pipelines.

The relative fractions for failure frequencies corresponding to mechanisms assessed to be length dependent and length independent are uncertain. Whether the length independent failure mechanisms materialize within the first 10 km or extend also beyond 10 km is assessed to be dependent on the pipeline and fluid specific factors discussed above. Nevertheless, it is assessed that the failure frequency is likely to be reduced after a certain distance.

With the failure data and pipeline population data corresponding to PARLOC steel pipelines and length categories 0-3 km and 3-10 km, combined with NCS 2024 data for steel pipelines transporting unprocessed fluid, results in a failure frequency estimate of 4.3E-04 per pipeline km-year.

Failure data and pipeline population data corresponding to PARLOC steel pipelines and length categories 10 – 30 km result in a frequency estimate which is more than one order of magnitude lower than for pipelines up to 10 km. This pipeline category is however assumed to be represent a mix of pipelines transporting processed and unprocessed fluids.

Considering the uncertainties discussed above, three failure frequency model alternatives are presented, where the third alternative is a combination of the first two. Alternative 1 is a model based on proportionality between failure frequency and pipeline length. Alternative 2 assumes that the failure frequencies associated with certain failure mechanisms are likely to occur within a the first section of the pipeline, and thus that the failure frequency per pipeline-km will be reduced for when exceeding a certain length. Alternative 3 combines the first two alternatives in a way where alternative 1 applies for pipelines with a length up to a certain distance, L_1, while alternative 2 applies for pipelines with a length exceeding L_1.

The two model alternatives are presented in the equations below.

- Alternative 1: Except for the separate contributions, the failure frequency is proportional to pipeline length.

$$f = f_{km,1} \times L_{pipeline} + f_{separate\ contributions} \qquad [1]$$

- Alternative 2: For this alternative a part of the failure modes is proportional to pipeline length and the other part is not (same frequency for all pipelines).

$$f = f_{km,2} \times L_{pipeline} + f_{pipeline} + f_{separate\ contributions} \qquad [2]$$

- Alternative 3: This alternative combines the first two alternatives in a way where alternative 1 applies for pipelines with a length up to a certain distance, L_1, while alternative 2 applies for pipelines with a length exceeding L_1.

$$f = f_{km,1} \times L_1 + f_{km,2} \times (L_{pipeline} - L_1) + f_{separate\ contributions} \qquad [3]$$

- *Note that there may be contributions to the total pipeline failure frequency from e.g. exposure to dragged anchors and ship foundering. These must be established separately.*

Model alternative 1

In model alternative 1 for steel pipelines transporting unprocessed fluid, considering the pipeline failure frequency is length dependant only, the recommended failure frequency is established based on the combined failure data and population data for PARLOC 2020 pipelines with length ≤ 10 km and NCS 2024 for steel pipelines transporting unprocessed fluid. The recommended failure frequency established applying model alternative 1 is thus:

- Length dependant contribution, $f_{km,1}$: 4.3E-04 per pipeline km-year.

Model alternative 2

In model alternative 2 for steel pipelines transporting unprocessed fluid, considering the pipeline failure frequency is partially length dependant and partially length independent, the empirical frequency established in model alternative 1 is split in two equal parts. The length independent part is normalised to a pipeline length of 10 km, i.e. half of the empirical failure frequency given per km, multiplied by 10 km.

Model alternative 2 thus include the following two contributions:

- Length dependant contribution, $f_{km,2}$: 2.2E-04 per km-year
- Length independent contribution, $f_{pipeline}$: 2.2E-03 per year

Model alternative 3

In model alternative 3 for steel pipelines transporting unprocessed fluid, the failure frequency per length is modelled similar to alternative 1 up to a certain distance, L_1. If the pipeline length exceeds L_1, the exceeding part of the pipeline is also modelled with a constant failure frequency, however lower than the first part of the pipeline. If applying L_1 = 10 km, this model alternative will be equal to applying alternative 1 for pipelines with a length up to 10 km, and applying alternative 2 for pipelines with a length exceeding 10 km.

Model alternative 3 includes the following two contributions:

- Length dependant contribution up to L_1, $f_{km,1}$: 4.3E-04 per km-year
- Length dependant contribution after L_1, $f_{km,2}$: 2.2E-04 per km-year
- Recommended L_1: 10 km

Summary

The failure frequency for well stream pipelines and other pipelines containing unprocessed fluid is merely an indicator and should be used with caution. Amongst the pipelines there is extensive variation within choice of materials, composition of oil and gas, temperature and other operational conditions. The variations in alternative 1 and 2 also reflects a significant uncertainty. As a baseline it is recommended to apply model alternative 3 presented above. This alternative reflects a reduction in failure frequency per pipeline-km for pipelines with a length exceeding 10 km, which is in general assessed to be reasonable.

The failure frequency contributions for the two model alternatives are summarised in Table 5-5.

Table 5-5 Recommended failure frequencies for 2”- 16” pipelines transporting unprocessed fluid

Well stream / unprocessed fluid		Failure frequency	Unit
Alternative 1:	$f_{km, 1}$	4.3 E-04	km year
Alternative 2:	$f_{km, 2}$	2.2 E-04	km year
	$f_{Pipeline}$	2.2 E-03	year
Alternative 3:	$f_{km, 1}$	4.3 E-04	km year
	$f_{km, 2}$	2.2 E-04	km year
	L_1	10	km
All alternatives:	$f_{Separate\ contributions}$	To be evaluated based on separate analysis.[11]	year

[11] This includes failures caused by dragged anchors (see Appendix E), and ship foundering (see Appendix D), as well as failures associated with subsea equipment attached to the pipeline system (see Chapter 5.2.7)

5.2.4.5 Steel pipelines outside the safety zone transporting processed fluid

Steel pipelines outside the safety zone transporting processed fluid are divided into two categories based on the pipeline diameter, i.e. pipelines with diameter ≤ 24” and pipelines with diameter > 24”.

In the previous edition of this report, it was suggested that a plausible distribution of length dependent failures and pipelines specific failures not explicitly length dependent contributes equally to the total steel pipeline failure frequencies (ref /1/). This suggestion was based on the following:

- Material defects are length dependent by nature.
- Damage due to external forces depends on the activity level in the pipeline area and is not explicitly dependent on length.
- Remaining failure causes can be equally distributed between length dependent and non-length dependent failure causes. The remaining failure causes are:
  - Corrosion (internal and external)
  - Structural failures
  - Natural hazards

The distribution suggested in ref /1/ is still recommended.

The total failure frequency established based on failures and pipeline population (for each pipeline diameter category) is divided in two equal parts. One half represents failure assessed to be length dependent, while the other half represents failure assessed to be specific for each individual pipeline, regardless of pipeline length.

The pipeline specific (length independent) contribution to the pipeline failure frequency is established using the score grade model presented in chapter 5.2.6. This contribution is thus based on a failure frequency per pipeline year and per score value, multiplied with a score value which must be established individually for each pipeline assessed. The failure frequency associated with the pipeline specific part, denoted f_{score}, is normalized both with respect to the average length of the pipelines covered by the respective pipeline populations, and an average exposure to various failure causes and mechanisms established for the two pipeline categories.

The failure frequency model for steel pipelines transporting processed fluid can be expressed as follows:

$$f = f_{km} \times L_{pipeline} + f_{score} \times v_{score} + f_{separate\ contributions} \qquad [4]$$

- *Note that there may be contributions to the total pipeline failure frequency from e.g. exposure to dragged anchors and ship foundering. These must be established separately.*

Steel pipelines transporting processed fluid, with diameters ⩽ 24”

The empirical frequency for steel pipelines with diameter ≤ 24” transporting processed fluid is established based on the NCS 2024 dataset for this category, combined with the PARLOC 2020 data for pipelines with length between 10 km and 100 km. The empirical frequency applying this data is 3.9E-05 per pipeline km-year. As discussed above the empirical frequency is divided in two equal parts, one assumed length dependent and one assumed to be dependent on pipeline specific attributes and exposure (i.e. not pipeline length dependent).

The pipeline specific fraction is first normalized based on the average length of the NCS 2024 population corresponding to this pipeline category. With an average length of pipelines in this population calculated to be 19.1 km, the resulting average pipeline specific contribution to the total failure frequency is 3.6E-04 per pipeline year.

The pipeline specific contribution shall also be based on a pipeline specific score established through assessment of the individual pipeline, see chapter 5.2.6. Based on a review of a set QRA's and HAZID reviews performed for pipeline included, and following the guideline given in chapter 5.2.6, an average pipeline score of 6.5 is established pipelines in this category. Thus, also considering the score established through a review of a specific pipeline within this population, the two contributions to the recommended failure frequency are:

- Length dependent contribution, $f_{km,\, D \leqslant 24"}$: 1.9E-05 per km-year
- Length independent contribution, $f_{score,\, D \leq 24"}$: 5.5E-05 per year, per score value

Steel pipelines transporting processed fluid, with diameter > 24"

The empirical frequency for steel pipelines with diameter > 24" transporting processed fluid is assessed to represent the pipeline population in the NCS 2024 dataset for this category, combined with the PARLOC 2020 pipelines with length exceeding 100 km.

For these pipeline populations there are however no recorded failures. It should be noted that there is an uncertainty regarding the inclusion of all pipelines covered in PARLOC 2020 with pipelines length ≤ 100 km in the category of pipelines with diameter ⩽ 24". In the NCS 2024 dataset there are pipelines with length ≤ 100 km that also have diameter > 24". It is reasonable to assume that some of the pipelines in the PARLOC 2020 populations with length ≤ 100 km should also be included here.

Thus, it cannot, based on the data and categories presented in PARLOC 2020, be ruled out that any of the failures included in the categories for pipeline lengths ≤ 100 km may coincide with pipelines with diameter > 24". And conservatively including two failures, while considering the combined population of steel pipelines in PARLOC 2020 with pipeline length exceeding > 100 km, and population of steel pipelines in NCS 2024 transporting processed fluid and with a pipeline diameter exceeding > 24", a failure frequency of 6.9E-06 is established.

The pipeline specific fraction is first normalized based on the average length of the NCS 2024 population corresponding to this pipeline category. With an average length of pipelines in this population calculated to 166,1 km, the resulting average pipeline specific contribution to the total failure frequency is 5.7E-04 per pipeline year.

The pipeline specific contribution shall also be based on a pipeline specific score established through assessment of the individual pipeline, see chapter 5.2.6. Based on a review of a set QRA's and HAZID reviews performed for pipeline included, and following the guideline given in chapter 5.2.6, an average pipeline score of 4.5 is established pipelines in this category. Thus, also considering the score established through a review of a specific pipeline within this population, the two contributions to the recommended failure frequency are:

- Length dependent contribution, $f_{km,\, D > 24"}$: 3.5E-06 per km-year
- Length independent contribution, $f_{score,\, D > 24"}$: 1.3E-04 per year, per score value

Summary

The failure frequency contributions for the two categories of pipelines transporting processed fluid are summarised in Table 5-6.

Table 5-6 Recommended failure frequencies for offshore pipelines containing processed fluid

Factor		≤ 24"	>24"	Unit
Length dependent failures	f_{km}	1.9 E-05	3.5 E-06	km year
Pipeline specific failures	f_{Score}	5.5 E-05	1.3 E-04	score grade-year
Other contributions	$f_{Separate\ contributions}$	To be evaluated based on separate analysis.[12]		year

5.2.5 Hole size distribution

The severity of the consequences of a failure is dependent on hole size. In addition to the failure frequencies presented for risers, jumpers, and pipelines, in chapters 5.2.2, 5.2.3, and 5.2.4, it is important to establish a hole size distribution.

5.2.5.1 Hole size data

PARLOC 2020

In the data provided by PARLOC 2020 the hole size information is limited. However, a distribution is provided based on failures with known hole size and redistributing the failures with unknown hole sizes to the extent and precision possible.

PARLOC 2020 concludes that the number of failures is not large enough to give separate hole-size distributions for risers and pipelines. The distributions are however given separately for flexible risers & pipelines, and steel risers & pipelines, and a separate distribution is also given for jumpers. The hole size distributions suggested by PARLOC 2020 is presented in Figure 5-4.

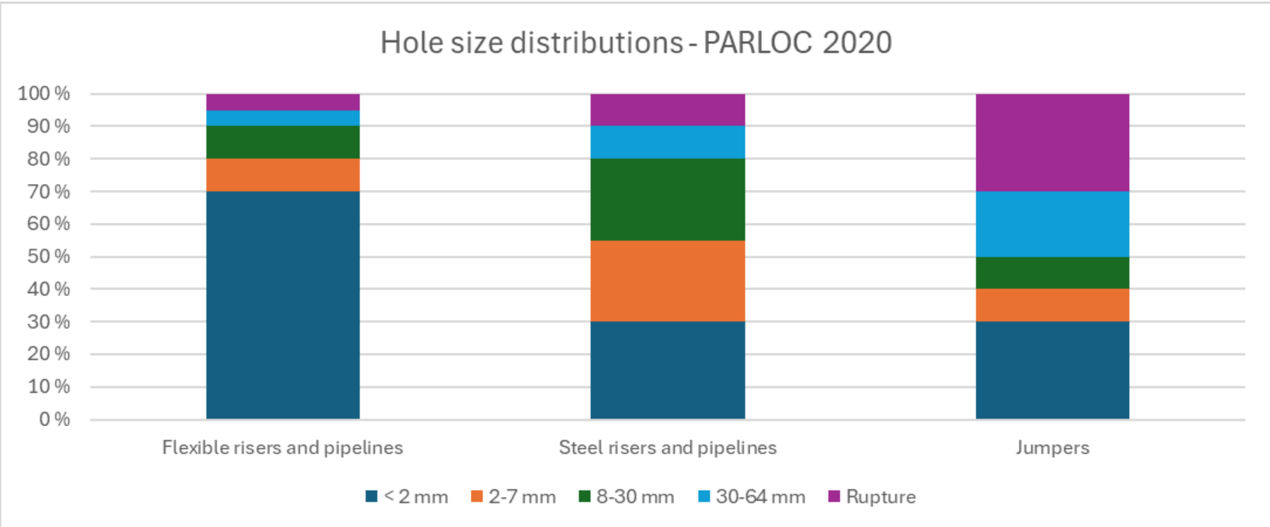

Figure 5-4 PARLOC 2020 hole size distributions for flexible risers and pipelines, steel risers and pipelines and jumpers

12 This includes failures caused by dragged anchors (see Appendix E), and ship foundering (see Appendix D), as well as failures associated with subsea equipment attached to the pipeline system (see Chapter 5.2.7)

NCS 2024

Exact information on hole size is for failures included in NCS 2024 is very often not available. For a large fraction of the failures the description does however give a good indication of the hole size. Effort has been made to categorise he NCS 2024 data according to the hole size distribution presented in PARLOC 2020. It should however be emphasized that there is a significant uncertainty related to the exact distribution of the NCS 2024 data.

UK HCRD

The UK HSE Hydrocarbon Release Database (HCRD) was an important data source in the previous editions of this report. The UK HCRD includes details of leaks from risers and pipelines within the 500-meter safety zone, i.e. excluding leaks in the midline. This source was used in the previous version of this report. UK HCRD include details of 65 risers and pipelines failures for the period 1992-2021 and is presented in Table 5-7. UK HCRD also include information on hole sizes for the failures registered. Cumulative exceedance curve for hole sizes from riser and pipeline failures recorded in HCRD is shown in Figure 5-5.

The UK HCRD data covers a longer period than PARLOC 2020 and has estimates of hole sizes available for all failures. However, most of the failures with the largest recorded hole sizes occurred prior to the year 2000.

PARLOC 2012 together with HCRD was the basis for the previous edition of this report. Figure 5-6 shows hole size exceedance curves from the different UK data sources for risers and pipelines combined. ***HCRD all years*** refers to the years 1992-2021, ***HCRD after 2000*** refers to the years 2001-2021.

Figure 5-6 shows that the hole size distribution for risers and pipelines as presented in PARLOC has changed significantly from 2012 to 2020 toward larger fraction of smaller holes.

The figure also shows that the hole size distribution given from HCRD is heavily influenced by the data period used. HCRD includes data from 1992 and comparing HCRD and PARLOC 2020 reveals that there was a number of large leaks in the period 1990-2000 which is not included in the PARLOC 2020 which failures after the year 2003 only.

Table 5-7 Number of failures for Risers, pipeline s from HCRD

Risers / pipelines	Number of failures
Steel Pipelines	32
Flexible Pipelines	14
Steel Risers	14
Flexible Risers	5

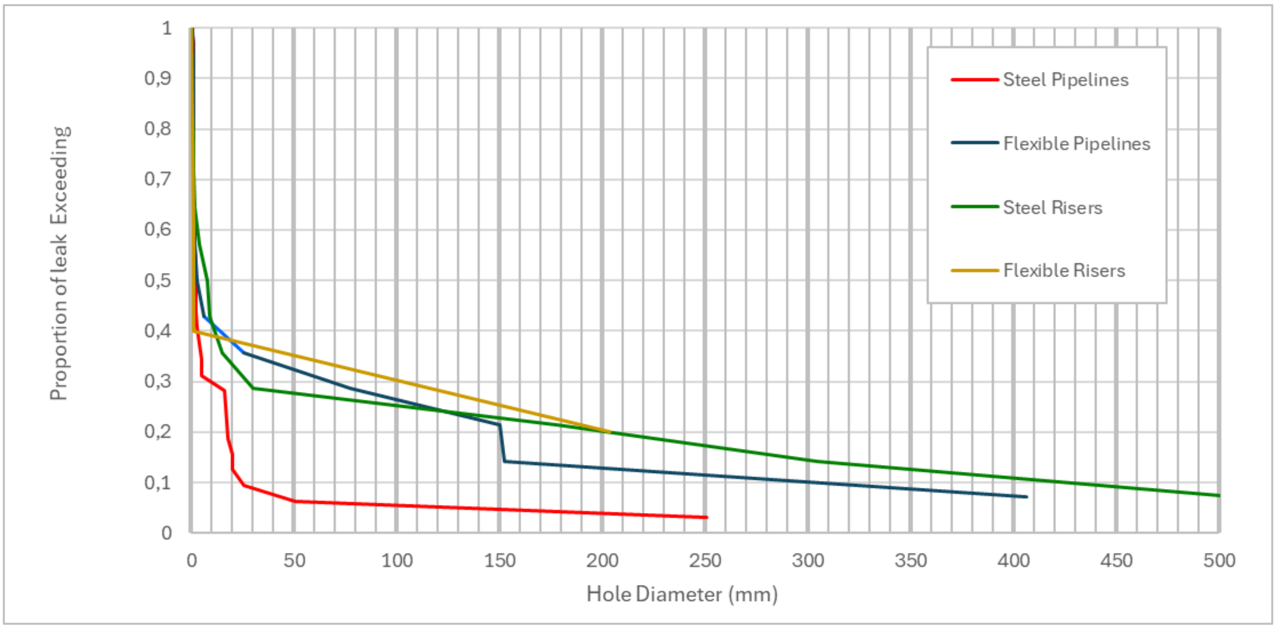

Figure 5-5 Cumulative exceedance curve for Hole sizes from riser and pipeline failures in HCRD

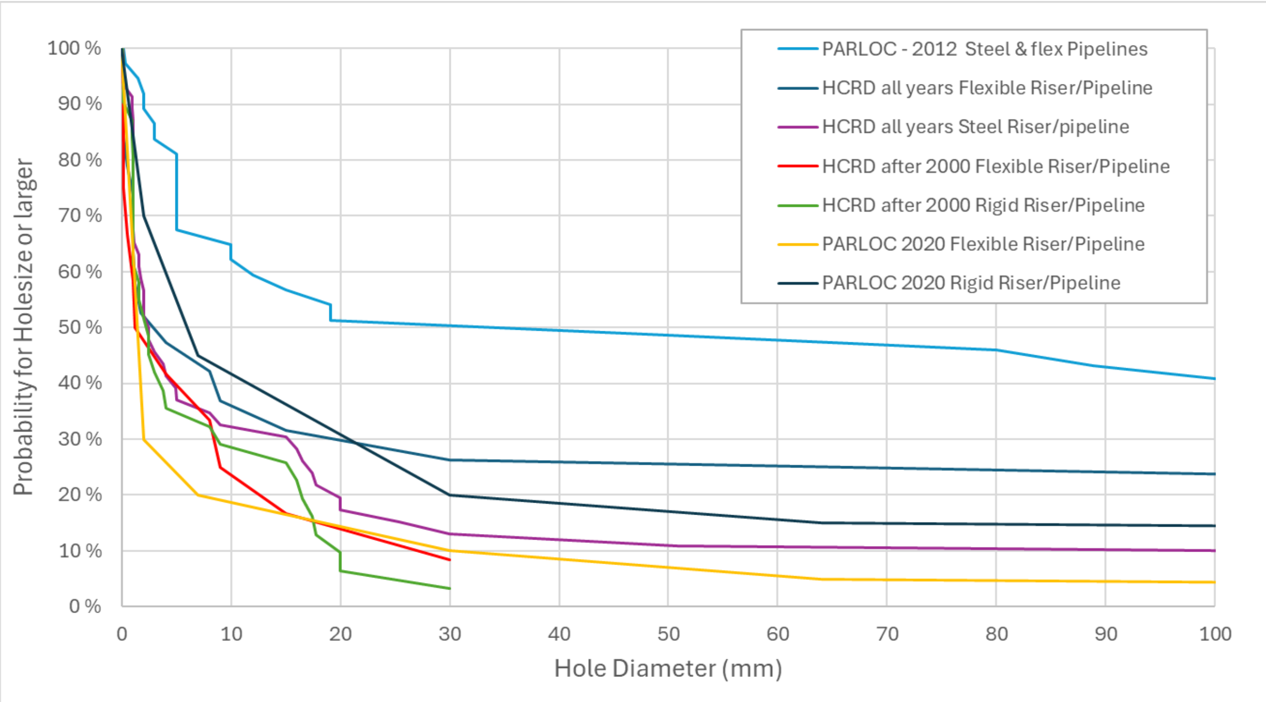

Figure 5-6 Hole size exceedance curves for risers and pipelines combined from different UK data sources.

5.2.5.2 Recommended hole size distributions

In the previous edition of this report four hole-size categories where defined (< 20mm, 20-80mm, > 80mm, and Rupture). In PARLOC 2020 five hole-size categories are defined, which is more refined particularly for small hole sizes. The PARLOC 2020 hole-size ranges are recommended used. The hole size distributions recommended in DNV 2017, and the distributions recommended in DNV 2025 (adopted from PARLOC 2020) is presented in Figure 5-7. It should be noted that the upper range represents full bore rupture, and the holes size upper range limit will obviously be depending on the pipeline diameter.

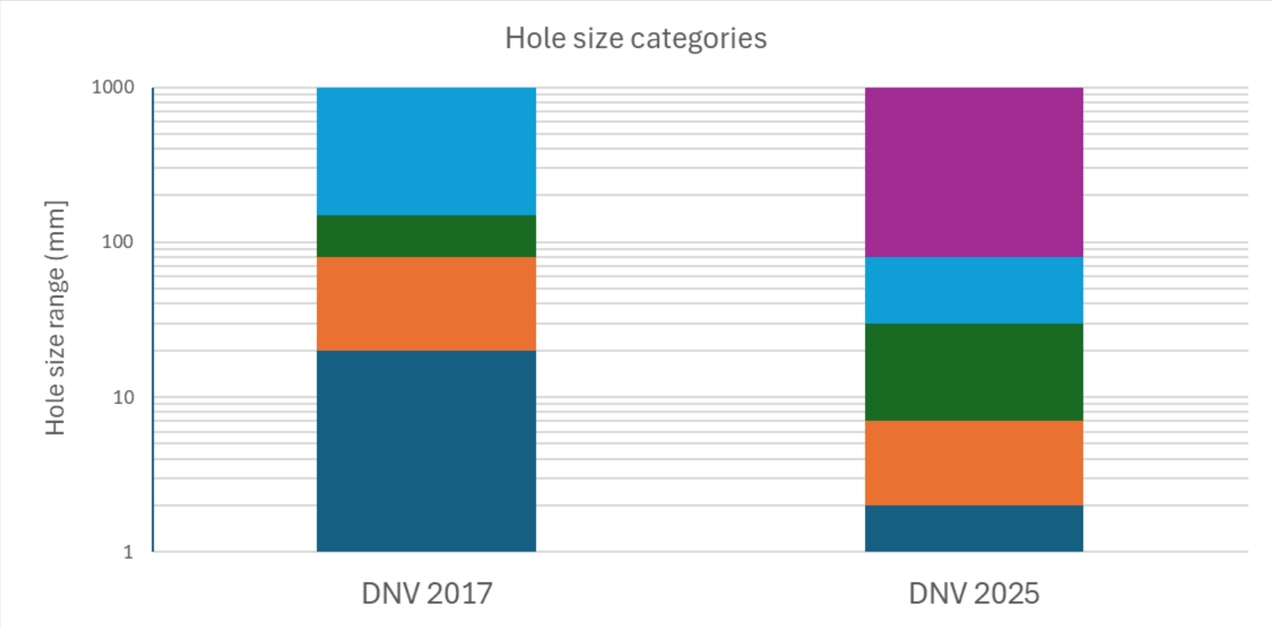

Figure 5-7 Hole size distributions and corresponding ranges.

Comparing the NCS 204 data with the PARLOC 2020 data shows that the fraction of smaller leaks in general is larger in the NCS 2024 data. The number of failures for steel risers and pipelines, as well as for jumpers are approximately twice as high in PARLOC 2020 dataset compared with NCS 2024. The number of failures for flexible risers and pipelines are comparable for the two datasets.

The following approach has therefore been used.

- The hole size distribution for flexible risers and pipelines is calculated as the average of NCS 2024 and PARLOC 2020.
- The hole size distribution for steel pipelines and jumpers is calculated as a weighted average, where the PARLOC 2020 distribution is given twice the weight as the NCS 2024 distribution.
- The hole size distribution for jumpers is adopted from PARLOC 2020.

The hole size distributions recommended based on the above, is presented in Table 5-8 and Figure 5-8.

Table 5-8 Hole size distribution for risers, pipelines and jumpers.

Category	Hole size range [mm]	Representative hole size [mm]	Flexible riser/pipeline	Steel riser/pipeline	Jumpers
I	< 2	1	60 %	40 %	40 %
II	2 – 7	5	15 %	20 %	10 %
III	7 – 30	20	15 %	20 %	10 %
IV	30 – 80	50	5 %	10 %	15 %
V	> 80	Pipe diameter	5 %	10 %	25 %

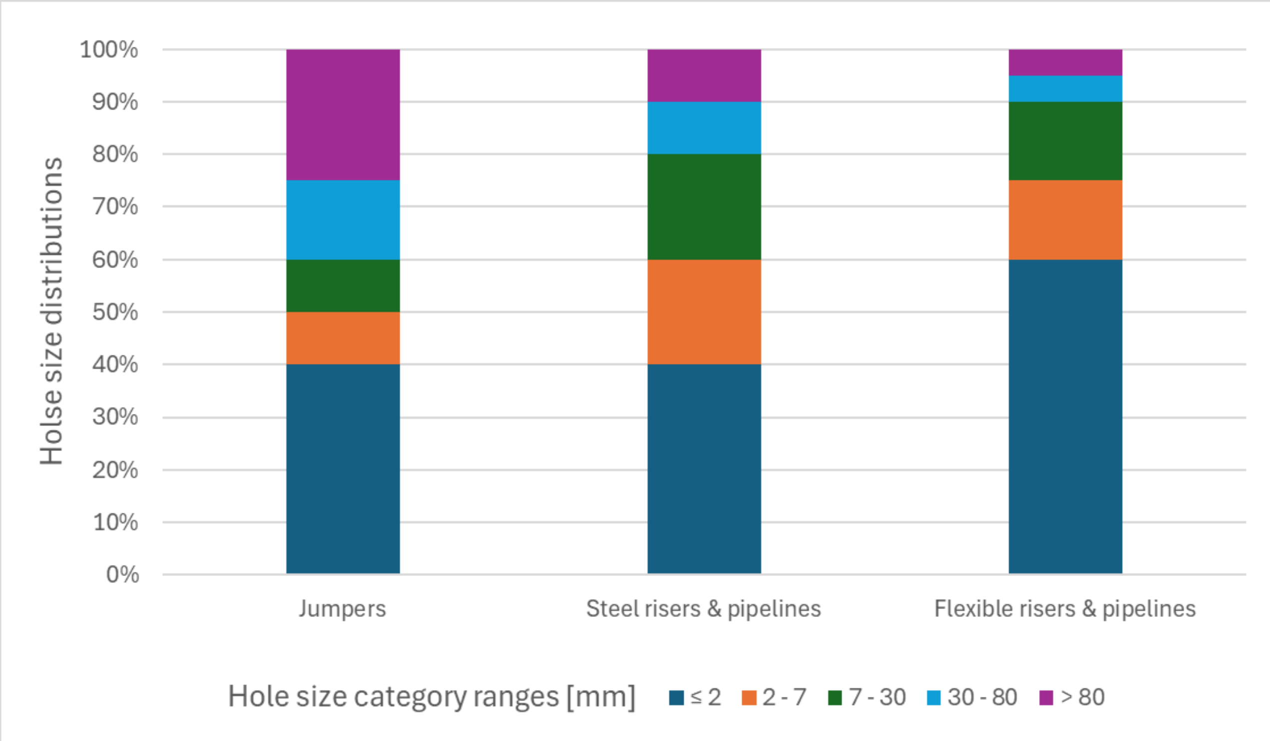

Figure 5-8 Hole size distribution for risers, pipelines and jumpers.

5.2.6 Assessment of individual pipelines, pipeline characteristics

5.2.6.1 Introduction

Pipelines are designed to withstand the loads defined during the design phase. Although all foreseeable and credible accidental loads are expected to be considered in the design phase, there is always a residual probability of having accidental loads exceeding the design loads, or unexpected development of failure mechanisms. The integrity of the pipeline will also be influenced by fabrication, installation, how the pipeline is operated and managed, as well as external activities and loads affecting the pipeline.

Each pipeline subject to analysis shall be assessed by a group of specialists within the fields of pipeline technology and risk analysis. The assessment shall be based on detailed knowledge about the pipeline. The assessment shall cover a set of pipeline characteristic potentially having a significant influence on the pipeline failure probability, however at the same time known to vary significantly between pipelines. The assessment will result in a total score for the pipeline subject to the analysis, which is the sum of the score values assigned to each assessed pipeline characteristic. The presented method is referred to as the *offshore pipeline score grade method*.

Scope and limitations

The characteristics presented in this chapter, the recommended scoring values, and the pipeline factor to be applied along with the total score to establish a failure frequency contribution, are all established for the offshore section of pipelines used for transportation of processed hydrocarbons. When applying the score grade method, it is thus important to note the following:

- The total score obtained from the grade method shall be multiplied by a pipeline factor which is calculated based on the empirical frequencies for the pipeline type (e.g. combination of pipeline material, inventory, and the environment where the pipeline is placed). The factor is thus dependent on the pipeline type, and if the score grade method is applied for a different pipeline type this factor should be re-established for this relevant pipeline type. Score grade factors are established for offshore steel pipelines transporting processed hydrocarbons with diameter up to 24” and with diameters above 24”. The score grade factors are presented in chapter 5.2.6.13.

- The recommended score values associated with the characteristics are assessed to be representative for pipelines transporting processed hydrocarbons. The influence of certain characteristics may be more or less critical depending on the pipeline material or transported fluid. Thus, the recommended score values associated with the various characteristics may not be applicable for other pipeline types.
- If applying the score grade method to a different pipeline type, it should also be assessed whether other pipeline characteristics not included in this model description (i.e. not assessed to have a significant influence on pipeline failure probability for pipeline transporting processed hydrocarbons) should be included and scored.

Scoring and score values

The pipeline threat assessment could be performed as part of a Hazard Identification session (HAZID) and used as a basis for assigning the scores.

There are generally two main causes that could result in pipeline failures. The first is related to external loads exceeding the pipeline’s load resistance, usually originating from an isolated incident, and causing failure immediately or within a very short time. The second is related to effects gradually weakening the pipeline over longer time which eventually results in a failure. A combination of the two may also occur, i.e. starting with an isolated incident causing a weakness in the pipeline, however not immediate failure, and due to the weakness resulting in accelerated further weakening over time due to effects such as e.g. corrosive environment or dynamics causing fatigue.

Examples of isolated incidents:

- Loads from trawl boards
- Anchor interaction / Ship loss

Examples of mechanisms acting over time:

- Corrosion, internal/external
- Open spans causing fatigue
- Buckling

The score to be set for the various characteristics ranges from 0 to 10, where increasing score is associated with increasing influence on the pipeline failure probability. Guidance is provided on how to apply score values for each of the characteristic included in the assessment. It is however important to note that there may be variation between pipelines and care should be taken when following the guidance presented in this report. The score values recommended in the guidance may not cover all variation in how pipelines are designed and operated.

Example of qualitative judgment of a characteristic and suggested corresponding score values:

- Score 0: The characteristic is not relevant or negligible for the pipeline examined
- Score 1-2: The characteristic is relevant, but the relevance / exposure is low and well managed
- Score 3-5: The characteristic is relevant, and the relevance / exposure is significant but managed
- Score 6-10: The characteristic is highly relevant and poorly managed

The following chapters describe potential failures modes and mechanisms related to each of the pipeline characteristics included in the score grade model. In order for the assessment to be balanced and consistent, detailed descriptions on how to judge and weight the different mechanisms and conditions related to the pipeline or the location are included.

The resulting failure frequency contribution associated with each characteristic is determined by the score value assigned. If the influences on the failure frequency associated with two (or more) different characteristics are assessed to be equal, the score values assigned for each of these characteristics should also be equal.

Changes to the score grade model in this report edition

For this edition of the report the score grade model presented in the previous edition was reviewed. The most notable changes are:

- The assessment of buckling is changed to include separate assessments for lateral buckling (mainly associated with exposed pipelines) and upheaval buckling (mainly associated with buried pipelines)
- Gross error is included as a characteristic. This is related to having a good basis for understanding the pipeline integrity, i.e. through well documented design, fabrication and installation, as well as adequate pipeline management through monitoring, ensuring conditions are in line with design specifications, inspections, analysis of inspection data/results, and ensuring relevant corrections, repair, and/or treatment is made when needed.

5.2.6.2 Loads from trawling activity

Loss of integrity records for pipelines and subsea equipment due to impact from trawling activities are relatively common in the NCS data set. In the RNNP data there are 30 such records. The majority of the incidents are minor, with damages typically limited to loss of coating. One incident resulting in a hydrocarbon leak is registered as caused by trawling.

In this chapter, the possible interaction between the pipeline and trawl gear is described. The information is retrieved from the DNV Recommended Practice F111 – Interference Between Trawl Gear and Pipelines /12/. The recommended practice contains an extensive description of the combination pipeline integrity and trawling. Som example sketches of trawling equipment taken from DNV-RP-F111 is shown in Figure 5-9.

Depending on design criteria, pipelines located in areas where trawling activity takes place may suffer immediate damage or long-term deterioration. In general, pipelines are designed to withstand loads from a trawl gear in areas where trawling activities is anticipated.

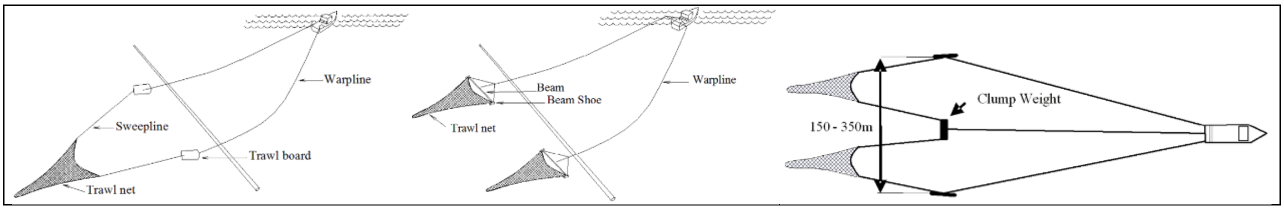

Figure 5-9 Example sketches of trawling equipment (ref. /12/)

The typical scenarios where the trawl gear could cause damage to the pipeline are impact, pull over and hooking:

- Impact, i.e. the initial impact phase when a trawl board, beam shoe or clump weight hits a pipeline. This phase typically lasts some hundredths of a second. It is mainly the local resistance of the pipe shell, including any protective coating and/or attached electric cable protection structure that is mobilised to resist the impact force.
- Pull-over, i.e. the second phase where the trawl board, beam trawl or clump weight is pulled over the pipeline. This phase can last from about 1 second to some 10 seconds, depending on water depth, span height and other factors. This will usually cause a more global response of the pipeline.
- Hooking, i.e. a situation whereby the trawl equipment is stuck under the pipeline. This is a rare situation where forces equal to or larger than the break load of the warp line are applied to the pipeline.

Both pull over and hooking can cause buckling to the pipeline. Impacts caused by the trawl board or other related gear (e.g. clump weights) combined with free spans could have negative impact on the pipe. Trawling with clump weights is a relatively new practice and consequently most pipelines are not designed to withstand loads from such equipment. Even though no serious damage due to clump weights are registered at this point, a hit by a beam trawl or clump weight could cause serious damage to the pipeline.

Trawl gear can also interact with related pipe equipment such as exposed flanges and bolts, and for small diameter pipelines, hooking may result in rupture.

Over the recent years, a scenario that has been given extra attention is when modern trawl boards with sharp edges hit and scrape field joints which are not protected by concrete coating but a rather soft material. Having these kinds of trawl boards frequently scraping the field joints may result in unprotected field joints with subsequent corrosion and crack initiation as well as loss of mechanical resistance. This being a relatively new phenomenon (both the sharp trawl boards and the new field joint coating) and the fact that possible negative impacts most likely will take time to develop into a leak makes failure frequency estimation for this scenario alone a complex matter. With a well-adapted inspection programme, potential initiated damages should be discovered before developing into a leak and repairs may be scheduled to a suitable time slot.

Buried pipelines are, unless the cover has been removed or the pipeline is buckling vertically and protruding the seabed (upheaval buckling, see chapter 5.2.6.9), generally assessed to be adequately protected against trawl gear. However, if the soil covering the pipeline or upheaval buckling have occurred in areas with trawling activity, it is assessed that the likelihood of damage due to loads from trawl gear is significantly increased. Free spans, particularly if exceeding design specifications, is also assessed to significantly increase the likelihood of damage due to loads from trawl gear. Pipeline inspection at intervals specified in design is thus an important barrier to confirm that there are no major issues related to buckling and free spans in areas of trawling activity. Free spans and upheaval buckling are also discussed in chapters 5.2.6.7 and 5.2.6.9 respectively.

Guidance for score assignment:

- If the pipeline is not routed through any areas with trawling activity, the likelihood of damage due to trawling gear is assessed negligible, and it is recommended to apply score grade value 0.
- Alternatively, if the pipeline is routed through an area with trawling activity, however it is buried and has been inspected, analysed, and any identified issues have been corrected and / or repaired, within the last five years, it is assessed that the likelihood of damage due to trawling gear is very low, and it is also recommended to apply score grade value 0.
    - Otherwise, if the pipeline is routed through an area with trawling activity, it is buried, however it has not been inspected, analysed, and any identified issues have been corrected and / or repaired, within the

last five years, then it is assessed uncertain whether the pipeline is currently able to withstand loads from trawling activity. In this case it is recommended to apply score grade value 5.

- Alternatively, if the pipeline is routed through an area with trawling activity, the pipeline is exposed (not buried) however designed to withstand loads from trawling activities which it is currently (and foreseen) being exposed to, and also has been inspected, analysed, and any identified issues have been corrected and / or repaired, within the last five years, it is recommended to apply a score grade value 1.
    - Otherwise, if the pipeline is not designed to withstand loads from trawling, or the type of trawling gear (i.e. weight and potential impact loads) which the pipeline is currently exposed to has increased (or is not known) and exceeds the pipeline protection as per design, it is recommended to increase the score grade value to between 3 and 5, depending on whether the pipeline is exposed low, average, or extensive trawling activity.
    - If the pipeline has not been inspected, analysed, and any identified issues have been corrected and / or repaired, within the last five years, then it is assessed uncertain whether the pipeline is currently able to withstand loads from trawling activity. In this case it is recommended to apply an additional score grade value 5. *(E.g. if an exposed pipeline is routed through an area with average to high trawling activity, the pipeline is known not to be adequately protected against the loads of trawling gear currently used, and it has also not inspected and followed up within the last five-year period, then it is recommended to apply a score value between 8 and 10.)*

Note: When assessing the pipelines susceptibility to damage from trawling activity its design could be compared to recommendations given in DNVGL-RP-F111 and DNV-RP-F107, which among others take intensity of trawling and assessment techniques into account.

5.2.6.3 Ship loss and emergency anchoring

Pipelines located in areas with ship traffic are exposed to threats such as dragged anchors and ship loss. RNNP data contains nine incidents resulting in degradation or loss of integrity due to impact from anchors. One incident is recorded to result in a leak. Historically, this contributes about ~5% to pipeline failure frequency, but as this is based upon only one failure, this figure only gives an indication of the historical contribution. For pipelines located in areas with intense ship traffic, a separate failure frequency contribution based on statistical ship traffic should be added. This contribution includes impacts from sinking ships (ship loss), dragged anchors from emergency anchoring and dragged anchors from anchored ships.

Note that pipeline damage due to dragged anchors from ships in transit and ship foundering is covered separately (see Appendix C and D respectively).

Whether the ship traffic poses a threat to the pipeline or not depends on several factors. The most important ones are:

- Vicinity to known anchoring location
- Ship size distribution. Affects anchor size and chain length and strength.
- Water depth. Affects whether the anchor can reach the pipe or not.
- Protective measures (trenching, rock dumping etc.)

Guidance for score assignment:

- If the pipeline is not routed through or in the vicinity (~500 m) of an anchoring location, the likelihood of anchor impact is very low, and it is recommended to apply score value 0.
- However, if all the below listed conditions are true, it is recommended to apply score grade value 1:
    - The anchor chain length of vessels using this anchoring location exceeds the sea depth where the nearby pipeline is located.
    - The pipeline is not dimensioned for anchors of the size used by the vessels using this anchoring location.
    - The pipeline is not adequately protected (buried or covered) against the loads of anchors corresponding to the vessels using this anchoring location.

5.2.6.4 Explosives from war activities

There are pipelines located in coastal areas where mines were deployed during years of war. Before installation of the pipeline the seabed is surveyed, and if explosives are found they will be cleared. In such areas there may however still be explosives that are not identified which will still pose a threat to the pipeline.

Guidance for score assignment:

- If the pipeline is routed through an area where mines were deployed during years of war, assign score value 1.
- Otherwise, assign score value 0.

5.2.6.5 Internal corrosion

The pipeline material is susceptible to corrosion both internally and externally. This chapter covers internal corrosion, while external corrosion is discussed in chapter 5.2.6.6.

Corrosion may be limited to a small area of the surface of the pipe, resulting in a small hole, or develop over a larger area of the pipe wall, causing loss of integrity, and ultimately resulting in rupture. In the case of local corrosion, the most significant parameters are wall thickness and rate of corrosion. In the latter case the capacity and integrity of the pipeline depends on the wall thickness, strength of material, difference between internal and external pressure, as well as diameter, shape and size of the corroded area.

The corrosion mechanism requires time to develop into a hole or rupture. With proper methods for monitoring the operation, inspection and analysis of inspection results at specified intervals, and following up identified areas of corrosion with adequate repair and treatment, failures due to corrosion can be reduced to a minimum.

The presence of internal corrosion is strongly dependent on the transported medium. For pipelines transporting dry gas internal corrosion is highly unlikely. Pipelines are more susceptible to corrosion if the stream include humidity and impurities. Monitoring the operations and fluid conditions is essential to ensure that the properties of the gas are within acceptance criteria. Proper maintenance of the equipment used for monitoring (e.g. dew point measurements) is required for the monitoring to be effective and reliable.

Pipelines where inhibitor is used to prevent corrosion have an additional potential source of failure since corrosion could reach critical levels if the effect of the inhibitor is changed or the supply is interrupted. For pipelines requiring inhibitor, reliable monitoring of the system for inhibitor is therefore very important.

Some corrosion mechanisms could cause pipeline failure within a short period of time. One example is sulphide stress cracking (SSC) which could have severe consequences if there are high levels of H_2S present and this has not been considered in design and choice of material.

Guidance for score assignment:

- If the transported fluid is in accordance with the pipeline design specifications, no corrosion inhibitor or scavenger is required as per design, the pipeline is continuously monitored and the operation is not deviating from the design intent, the pipeline is inspected at regular intervals (i.e. no less than every 10 years, and no less than specified in the design), and the analysis of the pipeline results shows that the corrosion rate is not exceeding the design rate, then the likelihood of having internal corrosion resulting in pipeline failure is very low, and it is recommended to apply score value 0.
- If corrosion inhibitor is required (either specified in design, or based on monitoring or inspection results), and even if the inhibitor is applied as specified, it is recommended to apply a minimum score value 1.
    - Otherwise, if corrosion inhibitor is not applied as specified in design or as deemed necessary per later monitoring and inspection results, it is recommended to apply a score value 3.
- If the pipeline is not inspected at regular intervals (i.e. no less than every 10 years, and no less than specified in the design), and thus the pipeline integrity is uncertain, it is recommended to add a score value 3.
- If the H_2S / sulphur level is exceeding design specifications, and it is not documented and deemed acceptable in a more recent analysis, it is recommended to add a score value 5.
    - Otherwise, if the composition of the transported fluid is in any other way not in accordance with design specifications, and it is not documented and deemed acceptable in a more recent analysis, it is recommended to add a score value 3.
- If scavenger or other chemicals are not applied in accordance with design specifications, or alternatively as documented and deemed acceptable in a more recent analysis, it is recommended to add a score value 1.

Note: Based on the above recommendations a total score of up to 12 (3 + 3 + 5 + 1) is possible if all conditions coincide. It is however recommended that a maximum score value of 10.

5.2.6.6 External corrosion

For offshore pipelines (excl. splash and tidal zones), external corrosion is unusual. It is however expected that the pipeline is inspected within regular intervals (i.e. no less than every five years, and no less than specified in the design). For buried pipeline in-line inspection can be used, for exposed pipelines both ROV and in-line inspection can be used.

Corrosion may develop due to ageing coating and / or if the anodic protection is no longer adequate. If the sacrificial anodes are consumed at normal rate, the system for corrosion prevention is effective. For offshore pipelines connected to installations, the pipeline and the installation are often galvanically connected, meaning that the pipeline and the submerged parts of the installation will share sacrificial anodes. Monitoring the rate of anode consumption can therefore be easier than if the structures were galvanically isolated. If anodes are consumed over a large distance, this could indicate that corrosion is ongoing.

Guidance for score assignment:

- If within the last five years inspections have been performed, results are analysed, and none of the two aspects listed below have been identified, the likelihood of having critical external corrosion is very low, and it is recommended to apply score value 0.
- Otherwise,
    - If the consumption rate of the sacrificial anodes are above normal rates, and/or are the anodes fully consumed, it is recommended to apply score value 1.
    - If there are bare sections of the pipeline, i.e. where the coating (primary barrier) is missing (e.g. caused by trawling gear, dragged anchor, or similar), it is recommended to apply an additional score value 1.

      Note: If buried, loss of coating is normally not considered being an issue.
- If the pipeline has not been inspected for external corrosion within the last five years, then the pipeline integrity is assessed to be uncertain, and it is recommended to apply score value 2.

5.2.6.7 Free span and fatigue

Issues related to design of free span pipelines are described in detail in the DNV-RP-F105 "Free Spanning Pipelines". Free spans can cause fatigue if the spanned section enters a vibrational mode by the flow. Under misfortunate circumstances the pipe may then burst in relatively short period of time. Some spans arise as the soil beneath the pipeline is washed away, and the length of the span can thereafter increase relatively fast since the free span affects the local currents close to the pipeline.

If the pipe has a free span exceeding the maximum free span length specified by design criteria, and is exposure to extreme weather conditions over time, pipeline failure may occur.

In the past, vortex induced vibrations (VIV) have caused pipeline failures, but today's pipelines are designed to resist loads related to such vibrations.

Guidance for score assignment:

- If inspections within the last five years can confirm that the pipeline is fully buried with no end spans, and that all free spans are within the acceptance criteria established in the design specifications or by later analysis, the likelihood of having a critical free span is very low, and it is recommended to apply score value 0.
- Otherwise, if inspections have not been performed within the last five years, it is recommended to assign a score value of 1 for each additional year, exceeding the above mentioned five years, since it was inspected, up to a maximum score 10 (e.g. if the above is not confirmed by inspection within the last 10 years, it is recommended to assign a score value 5).
    - If the pipeline is located either in shallow waters, areas with dynamic seabed, areas with harsh weather conditions, and/or areas with floods or similar unstable conditions, it is recommended to assign an additional score value 2.
- Otherwise, if inspection is performed, however free span exceeding the design criteria has been identified in such inspections, while assessed not imminently critical, it is recommended to apply a score value 3.

- If any issues related to fatigue, e.g. resonances outside of specification or assessed as an issue, or cracking such as hydrogen induced stress cracking, it is recommended to apply a score value 1-3 (based on assessed criticality).

5.2.6.8 Buckling – exposed pipeline

Buckling could occur if the pipeline is prevented from expanding when forces in axial direction arise as a result of changing pressure and temperature. This could cause buckling sideways or upwards. For exposed pipelines sideways or lateral buckling is due to gravity forces more likely than upwards buckling.

Exposed pipelines are often expected to buckle, particularly during the start of the operation. After a certain time, when the temperature and pressure condition have settled, the pipeline is expected not to buckle further. An exposed pipeline will normally buckle sideways, which is referred to as lateral buckling. It may however also buckle upwards, which is referred to as upheaval buckling.

Some pipelines are designed to allow for a controlled buckling to relieve axial tension. For new pipelines global buckling is normally expected, and measures are taken in design and installation to ensure the buckling occur in a certain buckling behaviour. I.e. in a way not resulting in significant weakening of the pipeline. If global lateral buckling occurs according to design, this is thus not regarded critical.

For older pipelines global buckling was also expected, however measures where not necessarily taken to ensure a certain buckling behaviour. The buckles occurring would normally have been assessed and in most cases the buckles would not to be critical.

It is important that the buckling is distributed over distance long enough not to cause unacceptable strain in the pipe. If global lateral buckling does not occur according to design, the buckling could be constrained to a very limited part of the pipeline, causing large strain which ultimately could result in failure and/or need for repairs.

Upheaval buckling from exposed pipeline is rare. If such buckling occurs, the pipeline will however be significantly more exposed to external loads.

Local buckling is normally the governing failure mode resulting from excessive utilization (sharp curvature) from a lateral buckle (exposed pipeline) or an upheaval buckle (buried pipeline, see next chapter). Local buckling appears as wrinkling or as a local buckle on the compressive side of the cross section. Local buckling can lead to excessive ovalisation and reduced cross-section area. This means reduced production, or even full production stop if e.g. a pig should get stuck. A locally buckled pipeline cannot stand an increased bending moment in the pipeline. This could lead to pipeline collapse and full production stop.

Guidance for score assignment:

- If the operating temperature is too low for lateral buckling, and/or global buckling has not lead to unacceptable conditions historically and the maximum flow conditions (temperature / pressure) have already occurred (i.e. flow conditions will be more and more favourable in the future), then the likelihood of lateral buckling is very low, and it is recommended to apply score value 0.
- If the pipeline has been designed to buckle laterally, it is being inspected when relevant (within 1 year after start-ups, modifications in operational conditions), and no critical lateral buckling is detected, then the likelihood of lateral buckling is very low, and it is recommended to apply score value 0.
    - If the pipeline has not been inspected when relevant (within 1 year after start-ups, modifications in operational conditions), it is recommended to apply a minimum score value 1.

- For each additional year, that the pipeline has not been inspected, it is recommended to assign an additional score value 1, up to a maximum score 5. (E.g. if not followed up within the last three years, assign a score value 3).

- If the pipeline has not been designed to buckle laterally in a controlled manner, however it is buckling laterally, it is being inspected when relevant (within 1 year after start-ups, modifications in operational conditions), and no critical lateral buckling is detected, then the likelihood of lateral buckling is low, and it is recommended to apply score value 1.
    - If the pipeline has not been inspected when relevant (within 1 year after start-ups, modifications in operational conditions), it is recommended to add a minimum score value 1, i.e. to apply a minimum score value 1+1.
    - For each additional year, that the pipeline has not been inspected, it is recommended to assign an additional score value 1, up to a maximum score 7. (E.g. if not followed up within the last three years, assign a score value 4).

5.2.6.9 Buckling – buried pipeline

Buried pipelines are normally not expected to buckle. If a buried pipeline starts to buckle it will buckle upwards where less force needed, i.e. result in an upheaval buckling.

When a pipeline is buried, the soil covering the pipeline is normally a measure to prevent impact from external loads such as trawl boards or anchors. If the pipeline protrudes out of the seabed, as an arc, the exposure to external loads will be significantly increased. If the pipeline is buckling, or expected to buckle, sufficient cover (e.g. rock dump) is required such that the upheaval buckle is not sufficient for the pipeline to protrude out of the seabed.

Guidance for score assignment:

- If the pipeline is transporting ambient fluid where the temperature difference is very small, the likelihood of upheaval buckling is very low, and it is recommended to apply score value 0.
- If upheaval buckling has never occurred, and the temperature is declining below the historic maximum and expected stay below this level, the likelihood of upheaval buckling is very low, and it is recommended to apply score value 0.
- Otherwise, if the pipeline is judged susceptible to upheaval buckling it is recommended to assign a minimum score value of 1.
    - If the pipeline is susceptible to upheaval buckling, and the pipeline has not been inspected, analysed and any identified issues are not corrected, repaired or treated, within the last five years, it is recommended to increase the score value to 3.
    - For each additional year, exceeding the five years mentioned above, that the pipeline has not been followed up, it is recommended to assign an additional score value 1, up to a maximum score 10. (E.g. if not followed up within the last ten years, assign a score value 3 + 5).

5.2.6.10 Landslide

Providing an accurate failure frequency contribution from landslides is a complex task and depends on the pipe's load resistance against this hazard. However, provided that the pipeline is designed in accordance with the DNV-OS-F101

“Offshore Standard” for “Submarine Pipeline Systems” or an equal standard, the failure frequency should be lower than 1E-04 per year and pipeline.

Guidance for score assignment:

- If the pipeline is routed through an area with increased likelihood for landslides, assign score value 1.
- Otherwise, assign score value 0.

5.2.6.11 Gross error

Gross errors are defined as failures during the design, fabrication and installation, and/or operation of the pipeline that may lead to a safety level significantly below what is aimed for by use of recognized industry standards for offshore pipelines. Generally, gross errors manifest themselves as failures due to the above covered mechanisms (i.e. related to corrosion, structural, third party, and natural hazard threats), however at a rate, or as a result of an accidental load, deviating significantly from what is considered in the assessments of above covered mechanisms.

Gross errors (human errors) shall be controlled by requirements for organization of the work, competence of persons performing the work, verification of the design, and quality assurance during all relevant phases, design, fabrication, installation, commissioning, and operation. Quality surveillance in the construction phase shall be performed by the operator or an inspectorate nominated by the operator. An integrity management system shall be established and maintained to ensure safety during operation. For more on gross errors, see DNV-ST-F101, DNV-RP-F116 and DNV-RP-F113.

Guidance for score assignment:

- If all the below listed conditions are satisfied the likelihood of gross error is assessed to be very low, and it is recommended to apply score value 0.
    - Pipeline construction - design, fabrication and installation (DFI) - is based on recognized industry standards, well documented and quality assured. The operator should for example be able to provide the DFI resume and ensure that documents referenced to in the DFI resume are in place and easily available; and provide or ensure the availability of QA/QC documentation including system pressure test, inspection reports, non-conformance reports, and any 3rd party verification or certification statements.
    - The pipeline is operated as intended, i.e. envelopes/limits for key parameters such as temperature, pressure, content, are well defined and adhered to. Various operational procedures are in place, implemented and continuously improved. The operations team is competent, experienced, and robust / stable. Reviews and/or audits are performed regularly within specified intervals.
    - The pipeline integrity is managed according to industry standards and best practices.
- Otherwise, if one of the three, two of the three, or all three, of the above-mentioned conditions are not satisfied, it is recommended to apply score values 3, 6 or 10 respectively.

Note: For pipelines which have changed ownership, or where the responsibility is changed from one operator to another, DFI documentation may to a various degree have been lost. However, if the pipeline has been operated by the same owner / operator for several years (more than ten years), by a competent, experienced, and robust team, and if monitoring, *inspections, and all relevant analysis are performed by the current owner / operator in a timely manner, this may compensate from lack of DFI documentation. In this case the uncertainty regarding the pipeline integrity should be assessed together with the operator.*

5.2.6.12 Parameters judged not applicable for score assessment

Length

Length is included as one of the parameters in the overall failure frequency model. Length will also affect the score assessment implicitly:

- Failure frequency contribution from trawling depends upon the length of the pipeline exposed to trawling.
- Failure frequency contribution from corrosion is to some extent related to length but strongly depends on what is causing the corrosion. If corrosion is caused by humidity in a gas pipeline, the length is not of importance.
- The length of areas where seabed conditions are such that free spans may arise will affect failure frequency. Long free spans will affect the failure frequency.

Material defects/Material failures

Failures and defects related to material are by nature explicitly length dependent and are therefore included in the length dependent part of the failure frequency. Adjustments may be justified if the pipeline subject to analysis is suspected to be especially prone to failures related to material.

Composition of transported medium

Gas (wet and dry) and oil should be properly processed and monitored in order to prevent corrosion or keep corrosion under control. As long as monitoring of composition of medium is confirmed to be adequate there is no need to add a failure frequency contribution related to the composition of medium.

Unknown causes

In addition to the known causes of failures to pipelines, as discussed above, new or unforeseen factors may cause failures to pipelines. Estimating the contribution from such unknown causes is not possible, nor is it possible to claim that some pipelines are more prone to failures related to unknown causes than others.

5.2.6.13 Score grade factors

With a change in the score grade characteristics, the guideline for scoring, as well as a change in the empirical frequencies and pipeline population, the score grade factor must be re-established.

The recommended frequencies for offshore steel pipelines transporting processed hydrocarbons are divided into a length dependant and a length independent contribution. The length independent contribution is based on the score grade factor, f_{score}, and the score value, v_{score}, which is obtained after scoring the various pipeline characteristics. The recommended pipeline failure frequency is calculated using the formula below[13]:

$$f = f_{km} \times L_{pipeline} + f_{score} \times v_{score} \qquad [5]$$

[13] This formula excludes the contribution from dragged anchor incidents.

For an average pipeline the length dependant and length independent contributions are taken as equal:

$$f_{km} \times L_{pipeline} = f_{score} \times v_{score} = \frac{f}{2} \quad [6]$$

The length dependent contribution is thus 50 % of the empirical failure frequency[14]; $f_{km} = f_{empirical} / 2$. While the score grade factor, f_{score}, can be established as:

$$f_{score} = \frac{f_{empirical} \times L_{pipeline,average}}{2 \times v_{score,average}} \quad [7]$$

Average pipeline lengths

The average pipeline lengths for offshore steel pipelines transporting processed hydrocarbons with diameters up to 24” and with diameters above 24”, is based on population data from the NCS and the UKCS:

- For pipeline diameters up to 24”: $L_{pipeline,\ average}$ = 19.1 km
- For pipeline diameters above 24”: $L_{pipeline,\ average}$ = 166.1 km

Average score grade values

The average score grade values are a prediction of the actual scores given to pipelines in future pipeline risk analysis when applying the updated score grade guideline. It should be acknowledged that the predicted average score grade values are assessed based on a coarse assessment of a limited selection of pipelines. All information required for applying the updated score grade guideline were not available, thus a significant degree of expert judgement has been applied when establishing the predicted average score grade values.

A total of ten pipelines were assessed according to the updated score grade guideline, five pipelines with diameter up to 24”, and five pipelines with diameter above 24”. The total score grade values established applying the new score grade guideline were compared with the total score grade values documented based on the score grade guidelines provided in the previous edition of this report (ref. /1/). The differences in score grade values obtained using the new score grade guideline vs. the old score grade guideline were used to adjust the average score grade values previously established applying the score grade guidelines provided in the previous edition.

The average score grade values applied to calculate the new score grade factors are:

- For pipeline diameters up to 24”: $v_{score,\ average}$ = 6.5
- For pipeline diameters above 24”: $v_{score,\ average}$ = 4.5

Score grade factors

Applying equation [7], with the average pipeline length figures, the average score grade values established, and the failure frequencies for steel pipelines transporting processed hydrocarbons gives the following score grade factors:

- For pipeline diameters up to 24”: f_{score} = 5.5E-05
- For pipeline diameters above 24”: f_{score} = 1.3E-04

14 The empirical failure frequency is also expressed a frequency per pipeline km.

5.2.7 Subsea equipment in hydrocarbon service

This chapter describes the methodology applied for the total estimation of failure frequencies for subsea equipment with regards to leak size categories statistical failure frequency data. Failure frequencies are estimated based on available statistics on failure frequencies for representative equipment. Where available, failure frequencies are aligned with failure frequency data in OREDA for subsea equipment.

It shall be acknowledged that failure frequency data for subsea equipment is limited. Reference is therefore given to equivalent topside equipment and justification provided on applied correction factors when applied to subsea equipment. The correction factors address the physical difference between topside and subsea equipment and considers relevant aspects of different design principles and codes.

Generally, subsea equipment is designed to a higher standard than topside equipment, considering the stricter limitations on inspection, maintenance, and service life. The main reference to topside failure frequency data is the “Process leak for offshore installations frequency assessment model” (PLOFAM), developed based on latest failure frequency data from the Norwegian continental shelf. The PLOFAM model is initially intended to provide failure frequency data for input to QRA, including distribution on leak size. The model has a truncation on minimum leak rate of 0.1 kg/s as this is the minimum reporting level in the NCS.

When applied to subsea equipment, correction factors are justified as described below.

The following approach is taken when establishing representative failure frequency data for subsea equipment:

A. Where OREDA subsea data are available, the PLOFAM model is adjusted with K-factor to align with the OREDA data. This option is only applied for subsea valves.

B. A default correction factor on PLOFAM topside failure frequency of K=0.5 is applied for subsea equipment, based on the normal practice. The approach is based on investigation of HC leaks in NCS indicating that approximately 50% of failures occur as a result of human interference / maintenance with equipment, which will not be the case for subsea equipment. The 50% reduction factor is applied as a basis to every equipment type, unless further evidence justified a different reduction factor, as described further in this chapter per equipment type.

C. Where subsea equipment is significantly different from topside equipment, a representation based on a combination of equipment available in PLOFAM has been used. This option is used for the compressors and pumps.

Further justification of the selected approach per equipment type is given in chapters 5.2.7.2 to 5.2.7.9

5.2.7.1 Hole size distribution

For subsea HC equipment it is suggested to apply hole size distribution in line with the PLOFAM methodology.

5.2.7.2 Base frequencies and K-factors

Applied base failure frequencies and K factors are given in Table 5-9 for what is to be considered a **best estimate (P50)** and sensitivity cases (P10) and (P90). P90 veers towards the PLOFAM topside data, while P10 is assessed as an optimistic estimated of subsea frequencies. The calculated base frequencies are given in Table 5-10. The frequencies are based on the base frequencies given in PLOFAM for topside equipment, ref. /28/ and justification provided in chapters 5.2.7.3 to 5.2.7.9. For application and calculation of failure frequencies with the updated base frequencies, it is referred to the PLOFAM report.

Table 5-9 Base frequency and K factors for equipment

Components (symbols from PFDs)	PLOFAM component(s)	Base frequencies	K factors		
		(1/equipment/year)	P10	P50	P90
Valves	**Valves:** Covering all valve types and sizes; frequencies are a function of equipment size. Failure frequency data aligned with available subsea data from OREDA	2.2E-04	0.1	0.2	1.0
Pressure cap and clamp connector	**Compact flange:** Pressure caps and clamp connectors are modelled as topside compact flanges.	3.0E-06	0.1	1.0	1.0
Instruments	**Instrument:** An instrument, including its valves and flanges, is counted as one instrument only. Hence, these valves and flanges should not be counted separately.	1.3E-04	0.1	0.5	1.0
Subsea pump	**Process vessel:** Subsea pump represented by a subsea vessel + 2 compact flanges	5.0E-04	0.1	0.5	1.0
Subsea compressor	**Process vessel:** Subsea compressor represented by a subsea vessel + 2 compact flanges + factor 2 compared to subsea pump to compensate for limited field history	1.0E-03	0.1	0.5	1.0
Scrubber and compressor cooler	**Process vessel:** It is not differentiated between types of vessel in the failure statistics. The vessel should be counted as a vessel with size equal to the main inlet/outlet of the vessel. Flanges, valves and instruments connected to a process vessel are counted separately as flanges, valves and instruments. Manholes are regarded as part of the vessel and are not counted separately.	5.0E-04	0.1	0.5	1.0
Flange (API)	**Compact flange: All subsea f**langes are modelled as topside compact flanges	3.0E-06	0.1	1.0	1.0
Seawater cooled heat exchanger	**Shell and tube heat exchanger:**	3.3E-04	0.1	0.5	1.0

Table 5-10 Base frequency for subsea equipment

Components (symbols from PFDs)	PLOFAM component(s)	Base frequencies (1/equipment/year)		
		P10	P50	P90
Valves	**Valves:** Covering all valve types and sizes; frequencies are a function of equipment size. Failure frequency data aligned with available subsea data from OREDA	2.2E-05	4.3E-05	2.2E-04
Pressure cap and clamp connector	**Compact flange:** Pressure caps and clamp connectors are modelled as topside compact flanges.	3.0E-07	3.0E-06	3.0E-06
Instruments	**Instrument:** An instrument, including its valves and flanges, is counted as one instrument only. Hence, these valves and flanges should not be counted separately.	1.3E-05	6.5E-05	1.3E-04
Subsea pump	**Process vessel:** Subsea pump represented by a subsea vessel + 2 compact flanges	5.0E-05	2.5E-04	5.0E-04
Subsea compressor	**Process vessel:** Subsea compressor represented by a subsea vessel + 2 compact flanges + factor 2 compared to subsea pump to compensate for limited field history	1.0E-04	5.0E-04	1.0E-03
Scrubber and compressor cooler	**Process vessel:** It is not differentiated between types of vessel in the failure statistics. The vessel should be counted as a vessel with size equal to the main inlet/outlet of the vessel. Flanges, valves and instruments connected to a process vessel are counted separately as flanges, valves and instruments. Manholes are regarded as part of the vessel and are not counted separately.	5.0E-05	2.5E-04	5.0E-04
Flange (API)	**Compact flange: All subsea** flanges are modelled as topside compact flanges	3.0E-07	3.0E-06	3.0E-06
Seawater cooled heat exchanger	**Shell and tube heat exchanger:**	3.3E-05	1.7E-04	3.3E-04

5.2.7.3 Valves

For subsea valves the best estimate on failure frequencies are aligned with available data from OREDA.

5.2.7.4 Flanges

Subsea standard flanges are modelled as compact flanges with no correction factor compared to topside compact flanges. Topside flanges are designed to different standards (API, ANSI, ASME…), hence the statistical data on topside flanges represent a wide range of different design. Based on the available statistics it is not straight forward to filter the statistics on flanges of different design. Subsea flanges are designed to a standard that is superior to several of the topside standards. Based on engineering judgement, subsea flanges are therefore represented by compact flanges.

In PLOFAM, failure frequencies for compact flanges, including sliding spools made up subsea are specified separately and based on failure frequency data for topside standard flanges with a correction factor of 5. Rationale is based on number of compact flanges installed and years in operation without any failures. Topside compact flanges are rarely interfered with. As a best estimate, failure frequencies for subsea compact flanges are considered identical to topside compact flanges.

5.2.7.5 Instruments

Failure frequency for equipment is based on failure frequency data given in PLOFAM for topside equipment with a default correction factor of K=0.5 as best estimate.

5.2.7.6 Pumps

Subsea pumps are considered field proven with 150+ units in operation over the last decades. To DNVs knowledge there have been no identified losses of hydrocarbon associated with subsea pump modules. Subsea pumps are fundamentally different from topside pumps, considering that the pump motor is fully encapsulated into a common vessel with the pump. Compared to a topside pump this removes any potential leak through the dynamic shaft seals. Representing a subsea pump by failure frequency data for a topside pump is therefore considered to be overly conservative.

Based on engineering judgement, the annual base failure frequency for each subsea pump is represented by one (1) subsea process vessel + two (2) compact flanges to represent pump inlet and outlet. A correction factor for subsea process vessel of K=0.5 is applied. No correction factor is applied for subsea compact flanges relative to topside.

All external equipment associated with the pumps such as flanges, instruments etc. are counted separately and included based on failure frequency per equipment.

5.2.7.7 Compressors

Subsea compressors are of similar design as subsea pumps. Similar to subsea pumps, a subsea compressor is significantly different from a topside compressor. Representing a subsea compressor by failure frequency data for a topside compressor is therefore considered to be overly conservative. Compared to subsea pumps, there is significantly less operating experience with subsea compressors. Based on this, the base failure frequencies for the subsea compressor modules are by engineering judgement and above arguments estimated to be a factor two (2) higher than for subsea pumps.

5.2.7.8 Process vessels

Subsea process vessels are modelled as a topside process vessel with a default correction factor on base frequency of K=0.5. Compared to a topside vessel, a subsea process vessel has no large diameter manhole.

5.2.7.9 Piping within subsea installations

Subsea piping associated with the SCSt is modelled as a percentage of the frequency contribution from equipment.

To estimate failure frequency from process piping, the number of meters of piping in the system in question should be estimated and used as input to the failure frequency model for piping. If the number of meters of piping is not available, the total contribution from piping is recommended set to 12 %. Thus, the failure frequency for all other equipment types should be multiplied by a factor 1/0.88 = 1.14 in order to get the total failure frequency including contribution from piping (Ref. /28/). In line with recommendations given in PLOFAM, piping is accounted for by adding 14% on total failure frequencies estimated for equipment[15].

[15] Actual length of piping is currently not available, and the percentage factor is considered to provide representation of piping leak frequencies with sufficient accuracy

5.3 Pipelines in hydrocarbon service onshore

5.3.1 Liquid pipelines failure frequencies

In ref. /16/ data material from CONCAWE from the years 1971 to 2022 is analysed and documented in tables and figures. The data is based on 435 failures and 35 307 km of oil pipelines. CONCAWE (ref. /16/) shows that the exposure for pipelines containing crude oil and products is approximately 1 400 000 km-years. The failure frequency for onshore oil pipelines distributed on diameter class is estimated based on these figures and are presented in Table 5-11. Frequencies from 2001 and 2022 are shown as a sensitivity.

The data contains no information on the number of incidents causing immediate or later repairs without a leak. Compared to offshore pipelines, the repair time is short.

The trend in the failure frequencies is shown in Figure 5-10.

Table 5-11 Failure frequencies for oil pipelines onshore 1971-2022 (ref. /16/)

Diameter range	Failure frequency		Denomination
	1971-2022	2001-2022	
Diameter < 8”	7.5 E-04	4.5 E-04	km-year
8” ≤ Diameter < 16”	3.7 E-04	2.0 E-04	km-year
16” ≤ Diameter < 24”	2.3 E-04	1.6 E-04	km-year
24” ≤ Diameter < 30”	1.7 E-04	1.2 E-04	km-year
30” ≤ Diameter	2.0 E-04	1.6 E-04	km-year

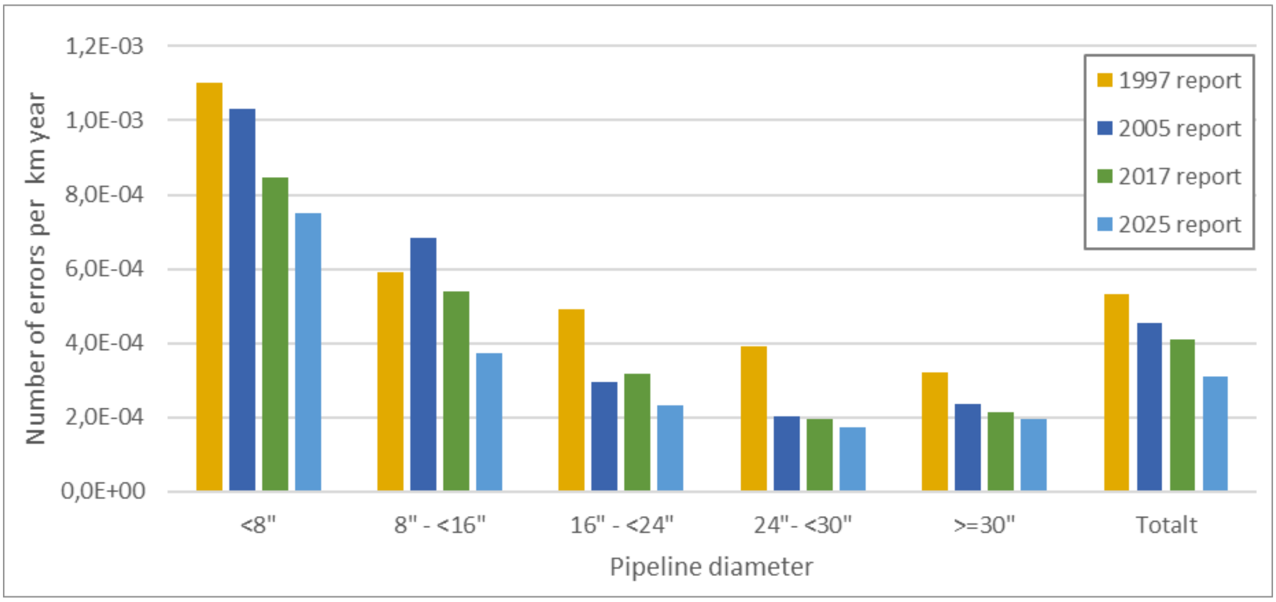

Figure 5-10 Trend in the failure frequencies for onshore oil pipelines[16]. Data from previous years are from ref. /2/.

16 The 2005 and 2010 (ref. /2/) report had the same frequencies.

5.3.2 Gas pipelines failure frequencies

The recommended failure frequencies in this chapter are based on data for onshore HC gas pipelines received from Equinor. The failure data covers the following failure mechanisms: construction defects, material failure, corrosion, external interference, ground movements (settlings, landslides etc.), hot tap made by error, stress corrosion cracking, pipeline fitting failure, other causes (e.g. lightning) and unknown causes. All failure frequencies are given per km-year. Pipelines laid through areas associated with certain types of threats, for instance frequent crossings of roads, railways, or unstable soil conditions, should be assessed in terms of an upward adjustment.

In the previous report edition (ref. /1/) the average failure frequency established for the period 2003-2013 was 1.5E-4 per km-year, while the updated frequency established based on the period 2008-2021 is calculated to 1.0E-04 per km-year (ref. /30/), giving a reduction of approximately 33 %.

It should be noted that the new data covers a somewhat smaller pipeline population. The recommended frequencies as presented in the previous report edition (ref. /1/) was based a 5-year running average failure frequency as basis. However, due to a smaller pipeline population, and correspondingly smaller failure data set, the failure frequencies recommended here is based on a 14-year period, from 2008-2021.

Generic recommended failure frequencies are given in Table 5-12 and Table 5-13, presented based on pipeline wall thickness and pipeline diameter respectively (ref. /30/). It is assessed that failure frequencies correspond better with pipe wall thickness, as the identified failure mechanisms are more affected by this than pipe diameter. If pipe wall thickness is known, it is thus recommended to apply failure frequencies presented in Table 5-12. Large pipe diameter is a factor very often coupled with large wall thickness, and if the wall thickness is not known, while the pipe diameter is known, then it is recommended to apply failure frequencies presented in Table 5-13.

More detailed failure frequencies for onshore steel pipelines transporting HC can be obtained using the onshore score grade model presented in chapter 5.3.4.

Although the pipeline populations used as basis for establishing recommended failure frequencies in this edition are not directly comparable the basis applied in the previous report edition, other sources such as EGIG (ref. /15/) and UKOPA (ref. /18/) indicates a positive trend in onshore gas pipeline safety.

The main causes for onshore gas pipeline failures are according to available statistics corrosion and external interference. These two causes contribute with approximately 30 % each to the recorded failures (ref. /30/). Construction defects and material failure are contributing with approximately 14 % and 8 % each. Similar distributions between causes for failure is also reported by EGIG (ref. /15/) and UKOPA (ref. /18/). Internal corrosion is very unusual, provided that the transported medium is dry gas. The likelihood of having water or other substances in the pipeline required for internal corrosion is very low when the transported medium is dry gas. The failure frequency due to corrosion is dominated by corrosion on the outside of the pipe wall caused by damaged or defective coating and/or cathodic protection, and weaknesses in connection with road or railway crossings.

The population of pipelines are rapidly decreases with increasing wall thickness. Pipelines with wall thickness above 15 mm constitutes approximately 10 % of the total pipeline population and include approximately 1 % of the failures recorded (ref. /30/). Due to the relatively small population and low number of recorded failures, a combination of quantitative and qualitative approach has been applied to estimate failure frequencies for pipelines with wall thicknesses exceeding 15 mm. For large diameter pipelines, 36 inches and above, the pipeline population and number of failures are also low compared the total pipeline population. Again, a combination of quantitative and qualitative approach has been applied to estimate failure frequencies for these larger diameter pipelines.

A more detailed failure frequency analysis can be made for a specific pipeline when required using the onshore score grade model (chapter 5.3.4). This model can address concerns related to exposure to specific failure modes or mechanisms. Such analysis should be done by qualified personnel, representing experience both in pipeline design and operation, as well as statistical analysis.

Table 5-12 Recommended failure frequencies for onshore HC gas pipeline, based on wall thickness (ref. /30/)

Wall thickness [mm]	Failure frequency	Denomination
≤ 5	2.2 E-04	km-year
5-10	1.0 E-04	km-year
10-15	1.1 E-05	km-year
> 15	1.0 E-05 (*)	km-year
Average	*1.0 E-04*	*km-year*

** Estimated based on limited available failure data.*

Table 5-13 Recommended failure frequencies for onshore HC gas pipeline, based on pipeline diameter (ref. /30/)

Pipe diameter [inches]	Failure frequency	Denomination
≤ 4	2.9 E-04	km-year
6-10	1.8 E-04	km-year
12-16	1.2 E-04	km-year
18-22	6.0 E-05	km-year
24-28	3.3 E-05	km-year
30-34	2.7 E-05	km-year
≥ 36	1.0 E-05 (*)	km-year
Average	*1.0 E-04*	*km-year*

** Estimated based on limited available failure data.*

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Based on available statistical material there is a strong relationship between wall thickness and failure mechanisms such as corrosion, external interference and ground movement. This is causing a significant decrease in failure frequency with increasing wall thickness. Based on this it is assessed that the pipeline wall thickness is likely to be better correlated with failure frequencies than pipeline diameter. The failure frequencies established per wall thickness, Table 5-12, is thus considered more robust than the failure frequencies established per pipe diameter, Table 5-13, and is recommended used.

The data presented in this chapter are also recommended for landfall areas, unless more specific data is available.

5.3.3 Hole size distribution

The hole size distribution for onshore pipelines are based on data from CONCAWE (ref. /16/), UKOPA (ref. /18/), and EGIG (ref. /15/). The hole size distributions are presented differently in the three data sources. UKOPA categorises the failures according to “Equivalent hole size class” given in [mm], while EGIG and CONCAWE categorises the failures in terms of types such as pinhole, crack, fissure, hole, split and rupture. For category *pinhole* CONCAWE specifies that the hole size is less than 2mm x 2mm, while EGIG specifies that the category *pinhole/crack* as a hole with effective diameter up to 20 mm. The hole size categories and corresponding failure fraction for the three data sources are presented in Table 5-14.

The hole size categories (denoted I to V) is in this report based on the hole diameter categories established in chapter 5.2.5 and presented in Table 5-15.

Table 5-14 Hole size categories and corresponding failure fraction (ref. /15/, /16/, /18/)[17].

CONCAWE		UKOPA		EGIG	
Category	Category	Category	fraction	Category	fraction
Pinhole	15 %	0 - 6 mm	66 %	Pinhole/crack	72 %
Fissure	17 %	6 – 20 mm	15 %	Hole	18 %
Hole	27 %	20 – 40 mm	12 %	Rupture	11 %
Split	19 %	40 – 110 mm	4 %		
Rupture	22 %	Above 110 mm	1 %		
		Rupture	3 %		

Table 5-15 Hole size categories used in this report.

Category	Hole size range [mm]	Representative hole size [mm]
I	Hole size ≤ 2	1
II	2 < Hole size ≤ 7	5
III	7 < Hole size ≤ 30	20
IV	30 < Hole size ≤ 80	50
V	Hole size > 80	Pipe diameter

The following assessments are applied to redistribute the fractions provided in the hole size distributions established by CONCAWE, UKOPA, and EGIG, to the categorisation used in this report (i.e. categories I to V):

- Based on the definitions given by CONCAWE, the hole type categories (as listed in Table 5-14) are assigned directly to the categorisation used in this report (I to V).
- For the first three UKOPA categories the fractions assigned to the categories I to IV by linear interpolation of the hole diameter specified for the two sets of categories.
- UKOPA category "40 – 110 mm" is assigned equally on hole size category IV and V, i.e. represented by hole diameters of 50 mm and pipe diameter respectively.
- UKOPA category "Above 110 mm" is together with category "Rupture" assigned to category V and will thus be represented by a hole size equal to the pipe diameter.
- EGIG category "Pinhole/Crack" is assumed to represent hole diameters up to 20 mm and is assigned to the categories I to III by linear interpolation.
- EGIG category "Hole" is assumed to represent hole diameters above 20 mm but not full-bore rupture. The fraction of failures in this category is assigned equally to category III and IV, while EGIG category "Rupture" is assigned to category V.

[17] Each hole category fractions is rounded to the nearest integer. Thus, the sums may deviate from 100 %.

A hole size distribution according to the categorisation used in this report is established by redistributing the fractions in the different hole size distribution presented by CONCAWE, UKOPA, and EGIG. Data from the three sources are weighted equally, regardless of the actual number of failures each set represents. The resulting fractions assigned to each category are however rounded off to the nearest 5 %.

The hole size is affected by several factors, for instance the mechanism causing failure, degree of utilisation (pressure), pipeline dimensions and whether the pipeline holds compressed gas or pressurized liquid. Next to initial failure mechanisms, degree of utilisation is considered to have the greatest impact on hole size.

The maximum allowed degree of utilisation for onshore pipelines is lower than for the equivalent offshore pipeline. Offshore pipelines are allowed to operate under pressure that results in steel material utilisation around 70-85% of specified minimum yield strength. Corresponding value for onshore pipelines is typically 40% in densely populated areas, with a gradually increasing exploitation with decreasing population density. In uninhabited areas, i.e. desert, the same degree of utilisation as for offshore pipelines is allowed.

The degree of utilisation is not known for the onshore pipelines subject to failure. However, the degree of utilisation for onshore pipelines is assumed to be less compared to oil and gas pipelines on the Norwegian continental shelf. For pipes with a high degree of material utilisation the holes are expected to be larger than for pipes with a lower degree of material utilisation. In this study 50 % of the category III and IV holes are assumed to develop into rupture if the material utilisation degree is larger than 70%.

The hole size distributions for onshore pipelines, based on utilisation factor, are summarized in Table 5-16.

Table 5-16 Recommended hole size distributions for onshore pipelines, based on utilisation factor.

Category	Hole size range [mm]	Representative hole size [mm]	Utilization ≤ 70 %	Utilization > 70 %
I	Hole size ≤ 2	1	15 %	15 %
II	2 < Hole size ≤ 7	5	25 %	25 %
III	7 < Hole size ≤ 30	20	35 %	17.5 %
IV	30 < Hole size ≤ 80	50	10 %	5 %
V	Hole size > 80	Pipe diameter	15 %	37.5 %

5.3.4 Assessment of individual pipelines, pipeline characteristics

5.3.4.1 Introduction

As described also for offshore pipelines in chapter 5.2.6, there may be aspects contributing to the pipeline failure frequencies that deviate significantly based on individual pipeline properties and the location of a specific pipeline.

This chapter presents a model for assessing a set of onshore hydrocarbon gas pipeline characteristic potentially having a significant influence on the pipeline failure probability, however at the same time known to vary significantly between pipelines. The assessment will result in a pipeline specific failure frequency considering the score values assigned to each assessed pipeline characteristic. The presented method is referred to as the *onshore pipelines score grade method*.

Characteristics

The following characteristics are assessed to have the largest contribution to the total onshore pipeline failure frequency and is included in the onshore pipeline score grade model.

1. External corrosion;
2. Internal corrosion;
3. 3rd party activity; excavation;
4. 3rd party activity; other (e.g. road and rail traffic, dropped objects);
5. Nature hazards; e.g. landslides, flooding, earthquakes; and
6. Gross error in design, fabrication, installation, and operation.

The failure frequency model also includes a failure category called *other*, representing 10 % of the total failure frequency. This contribution is kept constant, i.e. not subject to scoring.

Wall thickness dependency

The relative contributions to the total pipeline failure frequency, from each of the characteristics, are based on statistics comprising onshore hydrocarbon pipelines with varying pipe wall thickness and diameter. Based on available statistics (ref. /15/, /16/, /18/, /29/), the failure frequency contribution from each characteristic is found to have a strong dependency on pipe wall thickness. E.g. failures resulting from external corrosion and excavation is decreasing significantly with increasing wall thickness. The relative contribution from each characteristic is, based on the pipe wall thickness, assessed to deviate from the average contribution.

Deviations in failure frequency contribution from each characteristic is assessed for onshore hydrocarbon gas pipelines categorised by wall thickness. It is important to note that the deviation in failure frequency contributions has not been established based on pipeline diameter categories.

The average failure frequency contributions from each characteristic, and the failure frequency contributions from each characteristic associated with the different pipe wall thickness categories are presented in Table 5-17. The wall thickness category “5 mm < WT ≤ 10 mm” is modelled with relative contributions equal to the average pipeline. The relative failure frequency contributions from corrosion and 3rd party activities decrease with increasing wall thickness. As a result of this the relative failure frequency contribution associated with nature events and gross error must increase (the sum of all contributions must be 100 %).

The failure frequencies associated with the wall thickness categories are reduced with increase wall thickness (ref. Table 5-12). Thus, although the relative fraction associated with nature events and gross error is increasing with increased wall thickness, the resulting frequency contributions are still reduced. The “base frequency” contributions associated with each characteristic, and for each wall thickness category, is presented in Table 5-18.

Table 5-17 Relative failure frequency contributions per characteristic and pipe wall thickness category

Wall thickness category	Corrosion external	Corrosion internal	3rd party excavation	3rd party other	Nature hazards	Other	Gross error
Average	***20 %***	***10 %***	***20 %***	***5 %***	***5 %***	***10 %***	***30 %***
WT ≤ 5 mm	21 %	10 %	21 %	5 %	4 %	10 %	29 %
5 mm < WT ≤ 10 mm	20 %	10 %	20 %	5 %	5 %	10 %	30 %
10 mm < WT ≤ 15 mm	4 %	3 %	8 %	3 %	20 %	10 %	52 %
15 mm < WT	2 %	3 %	6 %	3 %	20 %	10 %	56 %

Table 5-18 Failure frequency contributions [annual per km] per characteristic and pipe wall thickness category

Wall thickness category	Corrosion external	Corrosion internal	3rd party excavation	3rd party other	Nature hazards	Other	Gross error
WT ≤ 5 mm	4.6E-05	2.3E-05	4.6E-05	1.1E-05	8.8E-06	2.2E-05	6.3E-05
5 mm < WT ≤ 10 mm	2.0E-05	1.0E-05	2.0E-05	5.0E-06	5.0E-06	1.0E-05	3.0E-05
10 mm < WT ≤ 15 mm	4.4E-07	3.7E-07	8.8E-07	2.8E-07	2.2E-06	1.1E-06	5.7E-06
15 mm < WT	2.0E-07	3.3E-07	6.0E-07	2.5E-07	2.0E-06	1.0E-06	5.6E-06

Frequency model

The frequency model considers the “*base frequencies*” and “*score values*” associated with each characteristic. The score values range from below 1 to above 1 and are essentially multiplicators applied to adjust the frequency contributions for the respective characteristics. The frequency model is presented below:

$$f = \sum_{characteristic} f_{base\_characteristic} \times score_{characteristic} + f_{other}$$

For each characteristic there is a defined minimum score value, $score_{characteristic}$, which is less than 1. Through the score grading process it is assessed whether the score value should be increased, and if so by how much. Starting of with a score value less than 1 reflects that the failure frequency contribution from this characteristic, for the pipeline being scored, may be lower than average. I.e. reflecting that the pipeline is considered “better” than average.

If $score_{characteristic}$ is set to 1 for all characteristics (or the weighted average of score values equal 1), the resulting failure frequency, *f*, will be equal to the average frequency for a pipeline in the respective pipe wall thickness category. If the exposure to a specific characteristic is assessed to be above average, the respective $score_{characteristic}$ value should exceed 1.

Score grading

The score grading activity is essentially to assess the pipeline with respect to the various characteristics listed above. For each characteristic the guideline suggests a list of aspects assessed to influence the failure frequency. If the exposure to, or hazard associated with, one or more of those aspects is assessed to be above the minimum level, the score value should be increased correspondingly.

Aspects relevant are typically associated with one of the “four layers of defence” against pipeline failure. These four layers of defence, or preventive barrier functions, are in line with the barrier system philosophy describe in DNV-RP-F116:

First layer: Pressure containment and primary protection

This layer of defence is related to the quality of the containment system, e.g. being fit for the operation it is intended for, and quality and adequacy of protection systems.

It includes design basis, i.e. providing a proper basis for understanding the premises and context the pipeline system will be/is operating in, and quality assured design, fabrication and installation (DFI) documentation, and management of change process.

Second layer: Operational/process control

This layer of defence is related to the daily operation and that the system is being operated as intended, e.g. ensuring that fluid compositions and process parameters are kept within the premises and specifications that the system is designed for.

Failure to control the operation may lead to e.g. pressure, temperature, cyclic (fatigue) loads, or exposure to chemical compounds, that the containment system and protection systems are not designed for. And thereby initiate or accelerate failure mechanisms.

Third layer: Pipeline integrity control

This layer of defence is related to strategies, systems, processes, and tools in place to ensure the pipeline integrity is being controlled. It includes monitoring, inspection, testing, but also review and assessments of the information and data obtained from the monitoring, inspection, testing activities.

The objective of this layer of defence is to identify defects that require further evaluations, evaluate selected defects by applying appropriate methods and adequate levels of detail, and if relevant provide recommendations for actions to improve pipeline integrity.

Fourth layer: Pipeline integrity improvement

This layer of defence is related to strategies, systems, processes, and tools in place to improve the integrity if or when needed. The integrity can be improved by maintenance and repairs of containment system or protection systems, but also by adjusting operational conditions, restricting the specifications for fluid compositions, or mitigating external exposure.

Within the four layers of defence some aspects are in this model sorted under Gross errors, while others may be associated with the various other characteristics. Within the first layer of defence there is several generic aspects, e.g.

quality assurance of DFI documentation, which is assessed relevant for failure modes associated with all the characteristics included in the score grade model. Within the other three layers of defence, strategies, plans, procedures, etc., which if not in place is also assessed to sort under the more generic Gross error characteristic. Specific systems, tools and activities related to e.g. internal and external corrosion management will however sort under these respective characteristics.

A guidance how to perform scoring is presented in chapters 5.3.4.2 to 5.3.4.7 for each of the six characteristics. In the guidance the link to each layer of defence is not explicitly given. There may be special features associated with a pipeline justifying deviations from the proposed score values associated with the various aspects to be assessed for a characteristic. The values proposed are however assessed to be a reasonable starting point, and it is expected that for most pipelines the proposed values will be appropriate.

Scope and limitations

The characteristics assessed relevant, and the recommended scoring values associated with relevant aspects and provided in the guidance, are all established for the onshore section of steel pipelines used for transportation of hydrocarbon gas. The failure frequency contributions associated with the various characteristics are found to be influenced by pipe wall thickness. The frequencies may also be influenced by factors such as pipeline material and transported fluid.

The score values to be established, as per the guidance given in chapters 5.3.4.2 to 5.3.4.7 should not consider the wall thickness. The dependency on wall thickness is already covered both in the “base frequencies” which is differentiated based on pipeline wall thickness categories (ref. Table 5-12), and also covered through adjusting the relative failure frequency contributions associated with each characteristic based on the wall thickness (ref. Table 5-18).

5.3.4.2 External corrosion

Corrosion is a natural process for a steel pipeline, and thus pipelines are designed to allow for some corrosion over its lifetime, i.e. applying a “margin” to the wall thickness (corrosion allowance). Pipeline coating and cathodic protection system are additional means to prevent external corrosion.

Coating is giving physical protection of the pipe material while the cathodic protection system is applied to ensure that the pipeline will become the cathode in an electrochemical cell and preventing the pipeline material from corroding. The cathodic protection can be provided using impressed current (ICCP) and/or sacrificial anodes (SACP). Due to variations in resistivity/conductivity the cathodic protection system is typically more complex for an onshore pipeline compared with pipeline submerged in water. For onshore pipelines possible changes in soil resistance and changes in external objects that may influence the CP protection (e.g. overhead power lines) should also be considered and managed.

To ensure external corrosion is prevented, the most important aspect to consider is to ensure the protection system is designed fit for purpose and operated, inspected and maintained according to the design and operational specifications. Inspection and monitoring of wall thickness (corrosion progression) is also important to avoid failure caused by external corrosion.

The minimum score value proposed for internal corrosion is 0.75. The aspects assessed to have the highest influence on external corrosion are listed in Table 5-19. It should be noted that the aspects listed in row 5a, 5b, and 5c are mutual exclusive. With the suggested score values presented in Table 5-19, the maximum score value, including the minimum score, is 3.00.

Table 5-19 Aspect to consider and guideline for scoring pipeline failure due to external corrosion

	Aspect to be considered	Score value
-	Lack of adequate external corrosion strategy and plans for inspection, monitoring and testing of pipeline and protection systems. (ISO 15589-1 is a relevant standard for Inspection and monitoring activities for ICCP system)	Assessed as part of gross errors
-	Lack of strategy and systems for maintenance and if necessary performing repairs.	Assessed as part of gross errors
1	Operational temperatures generally above allowed limit. (An increased fluid temperature can change the current demand for the pipeline protection system, and therefore the current output of the CP system (T/R unit). However, the anodes should not be affected as they are normally not attached to the pipeline.)	0.10
2	External corrosion protection has not been applied according to requirements.	0.40
3	Not in control of possible changes in external objects which may influence the CP protection (e.g. overhead power lines).	0.50
4	Not in control of / not monitoring potential changes in soil resistivity, e.g. resulting from more extreme weather (particularly drought and flooding) due to climate change.	0.50
5a	The remaining pipeline wall thickness and external corrosion protection system has not been inspected as planned.	0.75
5b	The remaining pipeline wall thickness and external corrosion protection system has been inspected as planned, but monitored data has not been reviewed by integrity management team at planned intervals.	0.50
5c	The remaining pipeline wall thickness and external corrosion protection system has been inspected as planned, the monitored data have been reviewed at planned intervals, but corrosion integrity and risk assessments are not performed as planned.	0.25

5.3.4.3 Internal corrosion

The minimum score value proposed for internal corrosion is 0.50. The aspects assessed to have the highest influence on internal corrosion are listed in Table 5-20. Note aspects listed in row 5a, 5b, and 5c are mutual exclusive, this is also the case for aspects 6a and 6b. With the suggested score values presented in Table 5-20 the maximum score value, including the minimum score, is 3.25.

Table 5-20 Aspect to consider and guideline for scoring pipeline failure due to internal corrosion

	Aspect to be considered	Score value
-	Poor or outdated design basis and design. Design life not specified, material selection not documented, design and operational condition not defined (e.g. P, T, fluid composition), means of internal corrosion control not defined.	Assessed as part of gross errors
-	Adequate internal corrosion strategy and plans for inspection, monitoring and testing of pipeline and protection systems are not in place.	Assessed as part of gross errors
-	Strategy and systems for improving internal conditions and if necessary performing repairs are not in place.	Assessed as part of gross errors
1	There is a need for internal corrosion protection system requirements, and this is specified in design documentation. Protection systems may include internal coating/lining/cladding, corrosion allowance, processing systems for removal of liquid water and/or corrosive agents, chemical treatment system, pig cleaning system. (Even if in place and applied according to requirements there is a potential for failure.)	0.10
2	Internal corrosion protection system required but not applied according to requirements.	0.40
3	Envelope violations fluid composition parameters[18]. Fluid composition not in accordance with relevant design specifications, and it is not documented and deemed acceptable in a more recent evaluation/analysis (e.g. pipelines re-used for other product types).	0.50
4	Envelope violations for process parameters. Temperature, pressure, water dew point, etc. not in accordance with relevant design specifications.	0.50
5a	The pipeline system has not been inspected as planned.	0.75
5b	The pipeline system has been inspected as planned, but monitored data (P, T, WdP, etc.) has not been reviewed by integrity management team at planned intervals.	0.50
5c	The pipeline system has been inspected as planned, the monitored data have been reviewed at planned intervals, but corrosion integrity and risk assessments are not performed as planned.	0.25
6a	Unacceptable or concerning internal corrosion damage development has been detected (based on ILI and subsequent integrity assessment). Correction has been performed. (There may be an increased potential for recurrence.)	0.10
6b	Unacceptable or concerning internal corrosion damages have not been properly managed/followed up to improve integrity (e.g. changes in internal conditions, chemicals, repairs)	0.50

[18] Special consideration should be taken if the H_2S level is exceeded for steel pipelines, or if the Oxygen level is exceeded for Cr13 (Chrome 13) pipelines. In such cases failure due to internal corrosion may develop rapidly.

5.3.4.4 3rd party excavation

For a pipeline routed entirely above ground it is reasonable to expect that excavation is not a relevant hazard. In this case, the score value for excavation may be set to 0.

For a pipeline that is buried a minimum score value proposed for excavation should be weighted based on what type of area it is routed through, and what measures that are in place to mitigate damage and failure due to excavation. Pipeline failure due to excavation may be sudden failure, or due to a physical damage resulting in e.g. damaged corrosion protection or causing tension / stress in the steel.

Measures to mitigate pipeline failure due to excavation damage include:

- Physical barriers, e.g. pipeline being routed through a concrete tunnel or under other type of cover.
- Operational barriers, e.g. policies for enforcing land use planning and the application of on-call systems for digging activities of external parties.
- Pipeline integrity management, including a strategy for inspection and monitoring that pipeline and protection systems are not damaged; ensuring that inspection and monitoring are performed according to planned intervals; and ensuring that repair and replacement are made if deemed necessary.

Area type is typically divided into *Urban*, *Suburban* and *Rural*. According to UKOPA (ref. /18/) and CONCAWE (ref. /16/), the failure frequency due to external interference is highest in suburban areas. However, the difference between suburban and rural areas is low. In the UKOPA dataset there are no incidents registered in urban areas. EGIG (ref. /15/) reports that increased cover depth is found to reduce the failure frequencies.

Aspect to consider and guideline for scoring excavation damage failure is listed in Table 5-21. Note that lines 2a – 2d are mutual exclusive. With the suggested score values presented in Table 5-21 the maximum score value, including the minimum score, is 3.75 for pipelines in suburban areas, however lower for pipelines in rural and urban areas.

Table 5-21 Aspect to consider and guideline for scoring pipeline failure due to excavation

	Aspect to be considered	Score value
1	The following minimum score value is suggested for pipeline based on the area type	Urban = 0.50 Suburban = 1.25 Rural = 1.00
2a	Adequate barriers to prevent excavation damage (physical and/or operational) are in place, and adequate pipeline integrity control and improvement are in place.	0.00
2b	Adequate barriers to prevent excavation damage (physical and/or operational) are in place, but adequate pipeline integrity control and improvement are <u>not</u> in place.	1.00
2c	Adequate barriers to prevent excavation damage (physical and/or operational) are <u>not</u> in place, but adequate pipeline integrity control and improvement are in place.	1.00
2d	Adequate barriers to prevent excavation damage (physical and/or operational) are <u>not</u> in place, and adequate pipeline integrity control and improvement are <u>not</u> in place.	2.50

5.3.4.5 Other 3rd party activity

Other external activities which may result in damaging a pipeline include onshore road and rail traffic, and exposure to lifted objects which may be dropped onto the pipeline. Vicinity to road and rail traffic, or exposure to objects lifted above the pipeline, are important aspects to consider, as well as the presence of barriers in place to prevent impact loads. As mentioned for excavation damage, pipeline integrity management is also an important aspect to detect damage and to ensure the damaged pipeline section is repaired or replaced.

A buried pipeline is assessed not affected by the types of 3rd party activity assessed here. Thus, for a buried pipeline the score value for other 3rd party activity may be set to 0.

Aspect to consider and guideline for scoring pipeline failure due to impact from road and rail traffic and dropped objects are listed in Table 5-22 and Table 5-23 respectively. The aspects are assessed not to be independent; thus, the score is dependent on several aspects combined. Each line in the tables represents one combination of the aspects to be assessed, and thus all lines are mutually exclusive.

If any other 3rd party activities with the potential for damaging the pipeline have been identified, it is suggested to perform a scoring of this activity in line with the guidance given for road and rail traffic and dropped objects. The score to be applied for this characteristic should be the sum of the score obtained from road and rail traffic, dropped objects, and other 3rd party activities if relevant.

Table 5-22 Aspect to consider and guideline for scoring pipeline failure due to road and rail traffic impact

	Aspect to be considered	Score value
1a	The pipeline is buried and/or there is no road or rail traffic in the vicinity of the pipeline Exposure to road and rail traffic can be neglected	0.00
1b	Exposure to road or rail traffic cannot be neglected Adequate measures to prevent impact to pipeline are in place Adequate pipeline integrity control and improvement are in place	0.50
1c	Exposure to road or rail traffic cannot be neglected Adequate measures to prevent impact to pipeline are in place Adequate pipeline integrity control and improvement are <u>not</u> in place	0.75
1d	Exposure to road or rail traffic cannot be neglected Adequate measures to prevent impact to pipeline are <u>not</u> in place Adequate pipeline integrity control and improvement are in place	1.00
1e	Exposure to road or rail traffic cannot be neglected Adequate measures to prevent impact to pipeline are <u>not</u> in place Adequate pipeline integrity control and improvement are <u>not</u> in place	2.00

Table 5-23 Aspect to consider and guideline for scoring pipeline failure due to dropped object impact

	Aspect to be considered	Score value
2a	The pipeline is buried and/or there is no lifting activity in the vicinity of the pipeline Exposure to dropped objects can be neglected	0.00
2b	Exposure to dropped objects cannot be neglected Adequate measures to prevent impact to pipeline are in place Adequate pipeline integrity control and improvement are in place	0.25
2c	Exposure to dropped objects cannot be neglected Adequate measures to prevent impact to pipeline are in place Adequate pipeline integrity control and improvement are not in place	0.40
2d	Exposure to dropped objects cannot be neglected Adequate measures to prevent impact to pipeline are not in place Adequate pipeline integrity control and improvement are in place	0.50
2e	Exposure to dropped objects cannot be neglected Adequate measures to prevent impact to pipeline are not in place Adequate pipeline integrity control and improvement are not in place	1.00

5.3.4.6 Nature hazards

Nature hazards with the potential to damage pipelines and cause pipeline failure typically include landslide, flooding and earth erosion, and significant earthquakes. There may also be other nature hazards.

It may be expected that a pipeline is designed according to expected nature hazardous loads, however due to changing climate the accidental loads where the pipeline is routed may exceed the design loads. Failure to ensure adequate design or to ensure measures adequate to mitigate currently foreseeable[19] accidental loads are considered gross error. It should be acknowledged that even with measures deemed adequate there is a residual risk associated with nature hazards. If a severe nature event occur the pipeline is assessed to be severely damaged. It may not fail immediately, however for this failure characteristic the effect of monitoring and inspection is assessed to be limited and thus not reflected in the suggested score guidance.

The minimum score value proposed for nature hazards is 0.50. Aspect to consider and guideline for scoring pipeline failure due to nature hazards landslide, flooding, and strong earthquakes are listed in Table 5-24, Table 5-25 and Table 5-26, respectively. Each aspect in the tables represents one degree of exposure, and thus all aspects are mutually exclusive. If any other nature hazards with the potential for damaging the pipeline have been identified, it is suggested to perform a scoring of this activity in line with the guidance given for landslide, flooding, and strong earthquakes. The score to be applied for this characteristic should be the sum of the score obtained from all nature hazards combined.

[19] Currently foreseeable may exceeding the accidental loads foreseen during pipeline design, fabrication and installation.

Table 5-24 Aspect to consider and guideline for scoring pipeline failure due to landslide

	Aspect to be considered	Score value
1a	The pipeline is not routed through any area where landslide is likely to occur	0.00
1b	The pipeline is routed through any area where the probability of landslide may occur, the probability is assessed not to exceed average	0.25
1c	The pipeline is routed through any area where the probability of landslide is known to be somewhat above average, however adequate mitigation measures are in place	0.25
1d	The likelihood of landslide in the area that the pipeline is routed through has not been assessed or is not known.	0.75
1e	The pipeline is routed through any area where the probability of landslide is known to be high (scoring to reflect assessed degree of exposure)	1.00 – 3.00

Table 5-25 Aspect to consider and guideline for scoring pipeline failure due to flooding causing erosion

	Aspect to be considered	Score value
2a	The pipeline is not routed through any area where flooding causing erosion is likely to occur	0.00
2b	The pipeline is routed through any area where the probability of flooding causing erosion may occur, the probability is assessed not to exceed average	0.125
2c	The pipeline is routed through any area where the probability of flooding causing erosion is known to be somewhat above average, however adequate mitigation measures are in place	0.125
2d	The likelihood of flooding causing erosion in the area that the pipeline is routed through has not been assessed or is not known.	0.40
2e	The pipeline is routed through any area where the probability of flooding causing erosion is known to be high (scoring to reflect assessed degree of exposure)	0.50 – 1.00

Table 5-26 Aspect to consider and guideline for scoring pipeline failure due to strong earthquakes

	Aspect to be considered	Score value
3a	The pipeline is not routed through any area where strong earthquakes is likely to occur	0.00
3b	The pipeline is routed through any area where the probability of strong earthquakes may occur, the probability is assessed not to exceed average	0.125
3c	The pipeline is routed through any area where the probability of strong earthquakes is known to be somewhat above average, however adequate mitigation measures are in place	0.125
3d	The likelihood of strong earthquakes in the area that the pipeline is routed through has not been assessed or is not known.	0.40
3e	The pipeline is routed through any area where the probability of strong earthquakes is known to be high (scoring to reflect assessed degree of exposure)	0.50 – 1.00

5.3.4.7 Gross error

Gross errors are defined as failures during design, fabrication and installation, and/or operation of the pipeline that may lead to a safety level significantly below what is aimed for by use of recognized industry standards for offshore pipelines. Generally, gross errors manifest themselves as failures due to other known failure mechanisms. The gross error failure may for example be deviation in specified design loads due to miscalculation or lack of quality control.

The minimum score value proposed for gross error is 0.75. Gross error are scored separately for each of the four layers of defence presented in 5.2.6.1, and follow the guidance presented in Table 5-27.

Table 5-27 Aspect to consider and guideline for scoring pipeline failure due to gross error

	Aspect to be considered	Score value
1	If any of the conditions below regarding *Primary Pipeline Protection* are not satisfied: - Design, fabrication and installation (DFI) have been based on recognized standards, is well documented and quality assured, A DFI resume, and documents referenced to in the resume, should be in place and easily available. QA/QC documentation including system pressure test, inspection reports, non-conformance reports, and any 3rd party verification or certification statements should be available. - There are no known construction defects, material failures/errors, design failures/errors, previously damaged pipeline/pressure containing components, or weld defects. - Protection systems against any identified and foreseeable failure mechanism are defined and assessed to be adequate. This may include pipeline cover, protection and support structures, information systems to third parties, restriction and safety zone systems, pressure protection system, external and internal corrosion protection systems, and more.	1.00
2	If any of the conditions below regarding *Operational/process control* are not satisfied: - The pipeline is operated as intended, i.e. envelopes/limits for key parameters such as temperature, pressure, content, are well defined and adhered to. - Operational procedures are established, implemented and continuously improved. - The operations team is competent, experienced, and robust / stable, and reviews and/or audits are performed regularly within specified intervals.	1.00
3	If any of the conditions below regarding *Pipeline integrity control* are not satisfied: - Inspection, monitoring, and testing are performed according to industry standards and best practices. - Integrity assessment is performed based on established risk-based strategies.	0.75
4	If any of the conditions below regarding *Pipeline integrity improvement* are not satisfied: - Strategies and contingency plans for how to handle unacceptable anomalies and damage are in place. - Systems and processes including procedures, tools and equipment, reporting systems, and qualified personnel are in place to ensure mitigations with regard to internal conditions, interventions with regard to external conditions, and repairs or replacement of the containment function and protection systems.	0.25

5.4 CO_2 pipelines

5.4.1 Onshore

The US Pipeline and Hazardous Material Safety Administration collects incident records for pipelines in the United States transporting hazardous material. This includes failures associated with CO_2 pipelines. The most relevant identified compilation of CO_2 pipeline failures is an article by Vitali et.al. (ref. /20/) which provides a statistical analysis of failures on onshore CO_2 pipelines based on the PHMSA database. The article by Vitali et.al. focused on analyzing the PHMSA incident data related to CO_2 pipelines operating in the US from 1994 to 2021. Onshore CO_2 pipelines have been installed in the U.S. mostly for enhanced oil recovery (EOR) applications.

Incidents corresponding to either of the following criteria should be reported to PHMSA:

- involve fatalities or injuries requiring in-patient hospitalizations,
- have $ 50,000 or more in total costs (including loss to the operators or the others, but excluding cost of gas lost),
- results in release of 50 barrels or more of product,
- result in an unintentional fire or explosion.

In 2020, approximately 8000 km of CO_2 pipelines were in operation in the US. According to Vitali et.al. (ref. /20/), the pipeline operating experience used for failure frequency calculation is estimated based on pipelines in operations since 1985. The failure frequencies presented by Vitali et.al. are based on a total of 113 failures registered between 1994-2021, while different sets of exposure, in km-years, have been applied. Vitaly et.al. concludes with an upper and lower annual frequency band corresponding to using an exposure period starting in 1990 or 1968 respectively, and at the end of the data period (i.e. in 2021) an annual CO_2 pipeline failure frequency between 2.5E-4 and 4.4E-04 per km-year was estimated. It should be noted that Vitaly et.al. reports an increasing trend in failure frequencies per km-years over the last two decades.

The cause contributing the most to the total failure frequency for the period 1994-2021 are Equipment failure (46 %). This category cover failure modes such as malfunction of control / relief equipment, pumps and pump related equipment, threaded connections and coupling failure, and defective or loose tubing or fitting. These are failure modes not considered when establishing failure frequencies for HC pipelines onshore or offshore. For the HC pipelines equipment failure is suggested modelled separately; for onshore pipeline systems using the PLOFAM leak frequency model, and for offshore pipeline systems using the recommended failure frequencies for subsea equipment presented in chapter 5.2.7.

Excluding failures assigned to the category *Equipment failure*, the failure frequency is reduced to between 1.4E-04 and 2.4E-04. Based on this it is recommended to apply an average failure frequency for onshore CO_2 pipelines (excluding equipment related failures) of approximately 1.9E-04 per year.

Vitaly et.al. does not provide a failure dependency on e.g. wall thickness or pipeline diameter. Although regarded as uncertain, it is recommended to apply a similar dependency on pipeline wall thickness as for onshore HC gas pipelines. Recommended failure frequencies for onshore CO_2 pipeline are presented in Table 5-28.

Table 5-28 Recommended failure frequencies for onshore CO_2 pipeline, based on pipeline wall thickness.

Wall thickness [mm]	Failure frequency	Denomination
≤ 5	4.2 E-04	km-year
5-10	1.9 E-04	km-year
10-15	2.1 E-05	km-year
> 15	1.9 E-05	km-year
Average	*1.9 E-04*	*km-year*

Effect of impurities in CO_2

The presence of impurities is an important topic of concern for CO_2 pipelines (ref. /24/, /25/). Keeping the CO_2 composition within design specification, i.e. for CO_2 pipelines, could be more challenging compared to process HC.

In the study of PHMSA data (ref. /20/), *corrosion* is found to be the third highest contributor to pipeline failures, after *equipment failure* and *material related defects*. Most failures caused by corrosion were however related to external corrosion (i.e. damage to coating or failure of cathodic protection), and not internal corrosion which would be the result of acid formation from impurities. It is also stated that "*Existing CO_2 pipelines such as U.S. pipelines reported in PHMSA database, usually apply a strict control in water content and some of them are operated with dry CO2.*"

Nevertheless, for CO_2 pipelines, high attention to managing internal corrosion is thus required. The main strategy is to avoid drop-out of a free water phase that due to formation of carbonic acid would be highly corrosive. Implicitly, the main strategy is strict control of water content in the CO_2 composition.

The industry experience covered in the PHMSA data does not necessarily reflect all CO_2 product specifications relevant for the wider range of emitters and capturing technologies for future large-scale CCS. With regards to internal corrosion, concern is identified to the presence of impurities (even at low levels) that through chemical reactions may form acids with high corrosion potential. This relates to chemical reactions between inorganic gas impurities NO_x (NO_2+NO), SO_x (SO_2+ SO_3), H_2S, O_2 and H_2O, forming nitric and sulphuric acid, and solids (e.g. elemental sulphur), with potential for corrosion. Other compounds being a potential source for sulphuric acid formation are COS, CS_2. COS and CS_2 can hydrolyse to H_2S and SO_2, which are reactants for the formation of sulphuric acid.

Prediction tools for setting up accurate limits of these gases to avoid precipitation of acids are not available. However, there are tools publicly available that can support the decision process for setting up tentative limits of acid producing components that can be used to design an appropriate test programme.

On the condition that the selected product specification is sufficiently qualified for the pipeline materials, it is foreseen that internal corrosion can be managed to a level comparable to current industry experience for CO_2 pipelines.

5.4.2 Offshore

No pipeline population data or failure data has been identified for offshore CO_2 pipelines. For offshore CO_2 pipelines a coarse assumption is made that the relative difference between the CO_2 and HC, established for onshore pipelines are also valid for offshore pipelines.

On the condition that the selected product specification is sufficiently qualified for the pipeline materials, it is foreseen that internal corrosion can be managed to a level comparable to current industry experience for CO_2 pipelines, which is assumed equivalent with processed HC. With this condition, the recommended failure frequencies for offshore CO_2 pipelines are listed in Table 5-29.

Table 5-29 Recommended failure rates for offshore CO_2 steel pipelines

Pipeline diameter [inches]	Failure frequency	Denomination
≤ 24"	7.2 E-05	km-year
> 24"	1.3 E-05	km-year

5.5 H_2 pipelines

Sufficiently good pipeline population and failure data for establishing historical failure frequencies for H_2 pipelines has not been identified. The H_2 pipeline population is still low compared with the pipelines transporting hydrocarbons and CO_2.

The HIAD database (ref. /19/) contains a wide variety of incidents associated with hydrogen equipment and leaks. The latest public available extract of data from HIAD, dated January 1st, 2024, includes 755 incidents and accidents. A search for the word “pipeline” in the data extract file returned 49 incidents and accidents. Most of these incidents and accidents are however associated with process piping within refineries, various plants (metallurgical, de-sulphuration, chlorine electrolysis, methanation, etc.) and hydrogen fuel stations. A total of 12 incidents and accidents were judged to be relevant for hydrogen transport pipeline systems. These include pipeline weld failures, blind flange, seal, and flow meter failure. The causes registered include excavation and agricultural drainage works, corrosion, erosion and soil settling, lightning strike, and hydrogen induced cracking in heat affected zones.

Another challenge with the data extracted from HIAD is that it is difficult to associate a population of pipelines matching the inclusion / exclusion criteria applied for the incidents included in the database. The database is also not based on a mandatory reporting scheme. Thus, the HIAD database cannot provide failure frequencies in terms of pipeline km-years, equipment-years, or any other exposure category.

H2Pipe in a Joint Industry Project lead by DNV and addressing transportation of hydrogen gas in offshore pipelines (ref. /21/). This is a joint industry project to develop the world's first guideline for transport of hydrogen gas in existing and new offshore pipelines. The aim for the new pipeline code, for design, construction and operation of offshore pipelines transporting hydrogen is to provide a pipeline safety target level equivalent to that of e.g. offshore pipelines transporting hydrocarbon.

Although not contributing with failure data as such, the expectation is that through application of a pipeline code tailored for H_2 pipelines, with a pipeline safety target level equivalent to the pipeline codes for HC pipelines, the failure frequencies for H_2 pipelines shall become comparable to HC pipelines. On the condition that the pipeline transporting H_2 is designed in accordance with a code specific for H_2 pipelines it is thus recommended to apply failure frequencies in the same order of magnitude as established for HC pipelines.

It should be noted that increased pipe wall thickness may be one means required in the H2 pipeline code, required to reach a certain safety target level. This is further complicated by the design operating pressure selected for the pipeline, which is also a factor affecting the wall thickness required to reach a certain target safety level. Adopting the pipeline failure frequencies, based on pipeline wall thickness categorisation established for HC pipelines, will not reflect that increasing the wall thickness may be a means to reach the same safety target level. Currently, the development of a hydrogen specific pipeline code is work in progress, ref. H2Pipe JIP.

For pipelines converted from transporting HC to transporting H_2, the utilisation (i.e. pressure) may be reduced as a requirement to meet the specified target safety level for a pipeline with a certain wall thickness. Whether or not this aspect will affect the failure frequency dependency to pipeline wall thickness (or pipeline diameter) is also uncertain.

Based on the uncertainties discussed above, it is suggested to revise the failure frequencies recommended for H_2 pipelines when more knowledge is established through H2Pipe JIP, or similar projects and initiatives. It is also suggested to revise the failure frequencies recommended for H_2 pipelines when more experience data is available. Due to the lack of experience with H_2 pipelines a margin of 20 % is added to the failure frequencies established for HC pipelines.

The recommended failure frequencies for onshore and offshore H_2 pipelines are presented in Table 5-30 and Table 5-31 respectively.

Table 5-30 Recommended failure frequencies for onshore H_2 pipeline, based on pipeline wall thickness.

Wall thickness [mm]	Failure frequency	Denomination
≤ 5	2.7 E-04	km-year
5-10	1.2 E-04	km-year
10-15	1.3 E-05	km-year
> 15	1.2 E-05	km-year
Average	*1.2 E-04*	*km-year*

Table 5-31 Recommended failure rates for offshore CO_2 steel pipelines

Pipeline diameter [inches]	Failure frequency	Denomination
≤ 24”	4.6 E-05	km-year
> 24”	8.3 E-04	km-year

5.6 Isolation joints

5.6.1 Background

The use of electrical isolation joint or insulation joint is primarily to avoid metallic or electrical contact between a cathodically protected pipeline and other structures. This minimizes current requirements and improves current distribution of the protected object and makes it easier to test and troubleshoot when errors are detected. Isolation joints are primarily used onshore, which is due to the number of surrounding structures such as compressor stations, pump stations, storage facilities, well sites (onshore), terminals and processing facilities. Isolation of pipelines can be beneficial also in controlling or limiting the effect of stray currents such as telluric currents, currents associated with an electric traction system, or currents from nearby structures under CP (ref. /31/).

Several CP standards regulate the use of isolation joints, such as ISO 15589-1 (ref. /32/) for onshore and ISO 15589-2 (ref. /33/) for offshore pipelines.

For offshore use isolation joints (IJ) can be installed in the landfall to separate offshore and onshore CP systems. Separation in the landfall is described in DNV-ST-F101 Sec. 6.4.5.4 which specifies that the needs for an isolation joint shall be evaluated at any landfall of an offshore pipeline with galvanic anodes and with impressed current CP of the onshore section. This requirement is slightly vaguer than the requirements in ISO 15589-2 which specifies that where offshore submarine pipeline CP is provided using galvanic anodes and onshore sections of the pipeline are protected using either impressed current or galvanic anodes, electrical isolation is necessary. To DNVs knowledge isolation joints topside on offshore structures is not commonly used. On fixed jacket structures with galvanic anodes, electrical connections between the steel risers shall be ensured. For flexible risers on floaters, there is usually an electrical connection through the flanges.

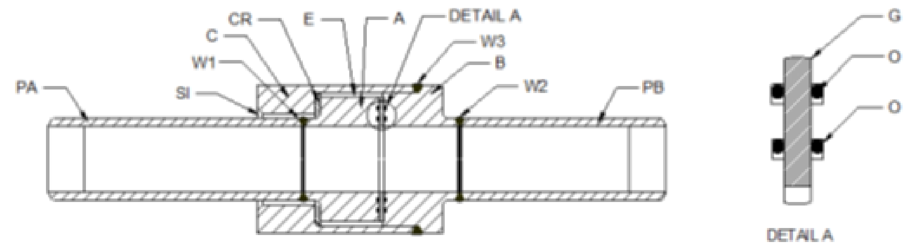
5.6.2 Types of isolation joints

There are several types of techniques for isolating different pipeline systems, where monolithic isolation joints (MIJ) are the preferred isolation method according to ISO 15589 series and which also is the focus in this study. Detailed descriptions of different isolation types can be found in NACE SP0286.

The design, materials, dimensions, and construction of the isolating joints shall comply with ISO 13623, EN 14161, EN 1594, or EN 12007-3 standards. A detailed description of a monolithic joint is shown in Figure 5-11. The conventional design uses multiple forgings joined by a few welds, often welded onto pup pieces for easy installation into the pipeline. An electrical isolation sheet, typically made of Glass-Reinforced Epoxy (GRE), is placed between the forgings. Two or more seals, like O-rings or spring-energized thermoplastic lip seals (for high pressure), seal between the electrical isolation sheet and the forgings. Epoxy resin fills gaps around the isolation sheet.

If the isolation joint is buried, an external coating to prevent current from bypassing through ground water shall be applied. For electrolytic fluids like seawater, at the inside surface of the isolation joint and the adjoining pipe for some distance shall be coated. Based on feedback and experience, a value of 100 Ω for the internal ohmic resistance is commonly used for the evaluation of the length of the internal coating.

These types of isolation monoblock cannot be disassembled on site and must be prefabricated and welded between the pipeline sections on site. All process wetted parts, metallic and non-metallic shall be compatible with the design service conditions (ref. /34/).



ITEM	ITEM DESCRIPTION	MATERIAL DESCRIPTION
A	FLANGE A	ASTM A694, GRADE F-52, LOW ALLOY STEEL
B	FLNAGE B	ASTM A694, GRADE F-52, LOW ALLOY STEEL
C	COLLAR	ASTM A694, GRADE F-52, LOW ALLOY STEEL
G	GRE RING A	NEMA LI 1 XR-302 GLASS REINFORCED EPOXY
CR	GRE RING B	NEMA LI 1 XR-302 GLASS REINFORCED EPOXY
E	EPOXY FILLER	2 PART COLD CURE EPOXY
PA	PIPE PUP A	NPS20, API 5L GRADE X52, WT(0.5)
PB	PIPE PUP B	NPS20, API 5L GRADE X52, WT(0.5)
SI	RTV SEALANT	SILICON PROTECTIVE SEALANT
O	O-RING	A5568 O-RING, FL

Figure 5-11 Isolation joint description including examples of materials. Taken from Ref. /35/.

5.6.3 Design, fabrication and Installation

For offshore pipelines, it is recommended to place the isolating joints at the landfall or on the seaward side of any emergency shut down valves. Short circuiting of the isolation joints shall be avoided, for instance through reinforced concrete structures or pipe support systems.

Isolating joint on a vertical or angled transition section should be considered to prevent a continuous water phase inside the pipeline becoming the source of internal corrosion.

Welding is the main method for assembling a Monolithic Isolation Joint (MIJ). Typically, three welds are required (see example inn Figure 5-12). Welds W1 and W2 are done before final assembly and do not risk overheating the non-metallic joint parts. Weld W3, the closure weld, holds the MIJ assembly together and is the last step, posing the highest risk of overheating and potentially damaging the internal components (i.e. glass reinforced epoxy, elastomer seal) that cannot be detected after completion.

Monobloc isolation joints shall be electrically tested before installation, requirements can be found in EN 12007-3.

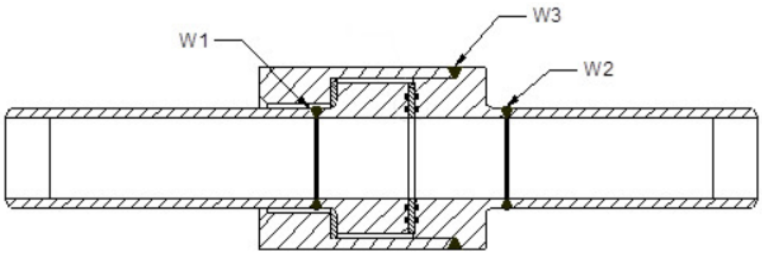


Figure 5-12 W1, W2 and W3 are welds

When installing electrical isolation points the risk of direct current (d.c.) stray currents should be considered, precautions should be taken to ensure that no corrosion is caused at the isolating joint by current flow across the isolating joint via the ground. This requires, for example, detailed measurements and analysis of the electrolyte surface gradients.

To protect the isolating joint against overvoltage, an isolating spark gap should be connected across the isolating joint. Spark arrestors are installed on the pipeline at each side of the isolation joint.

Requirement to pressure testing can be found in ISO 13623.

5.6.4 Failure types

It is believed that monolithic isolation joints are considered more robust, since these are prefabricated and should be subjected to a high degree of quality assurance/quality control (QA/QC) required during construction, assembly, and installation and that failures often are linked to operation. However, a study published by Chevron in 2014 (ref. /36/) showed that failures in a properly designed MIJ could also occur due to design errors. Figure 5-13 shows a dissected MIJ where the steel springs and elastomers had failed, due to poor material selection.

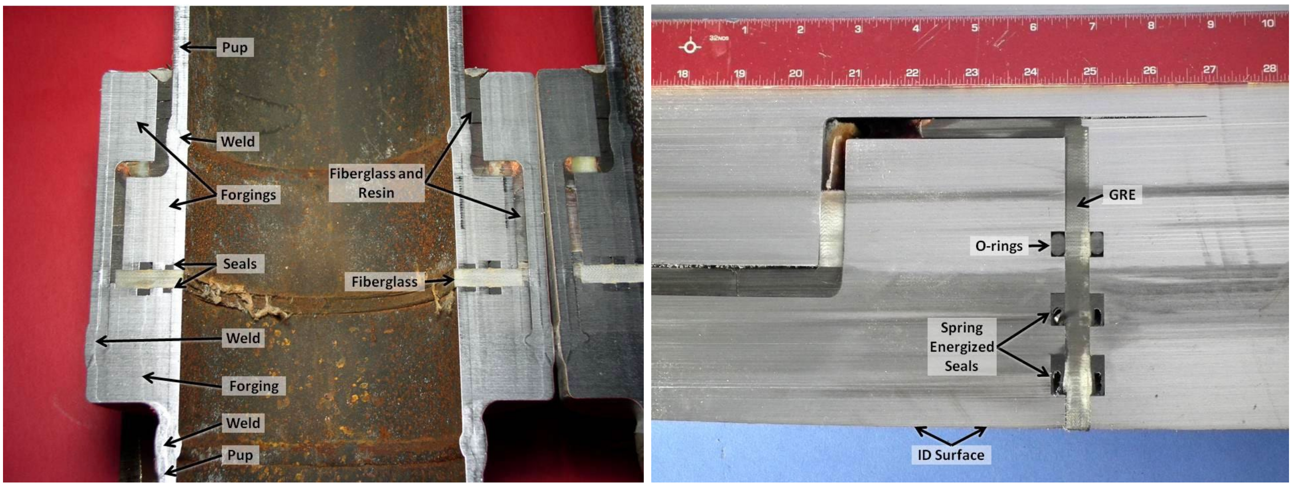


Figure 5-13 Left: dissected failed isolation joint (ref. /36/). Right: Close up view of a high pressure IJ after sectioning lengthwise showing six seals. The innermost two seals on each side are spring-energized seals. The outermost seals are O-rings. (courtesy Ref. /36/)

An overview of DFI and operational failure types for MIJ is listed in Table 5-32.

5.6.5 Recommended failure frequency

Although information regarding failure modes and examples of failure have been identified, no complete failure data set, nor exposure data, were identified in the review of isolation joints. Failure frequency based on empirical data thus cannot be established. It is assessed that the isolation joint is most likely a weak point on the pipeline with regards to containment, however likely to have a lower failure probability than e.g. a flanged connection.

With reference to the failure modes identified and listed in Table 5-32 it is expected that the design, material used, and installation of the isolation joint, as well as the operation of the pipeline and fluid composition will affect the failure frequency. Thus, it is expected that there will be a significant variation in failure frequency based on these aspects.

In general, it is recommended to apply a failure frequency for isolation joints equal to 50 % of the failure frequency established for a flanged connection on the same section of the pipeline.

Table 5-32 Typical failures for MIJ (ref. /35/, /36/)

Failure Type	Description	Causes	Consequences
Design, fabrication and installation			
Deformation of non-metallics	O-rings permanently deform to a rectangular shape, losing their sealing force.	Compression set due to viscoelastic stress relaxation, chemical exposure, or inadequate curing.	Loss of sealing force, leading to leaks.
Excessive Weld Hardness	Weld heat-affected zones exhibit hardness above acceptable limits.	High carbon equivalent in forgings, inadequate welding procedures.	Increased risk of sulfide stress cracking in the presence of H_2S and water.
Cracked Energizing Springs	Springs in spring-energized seals develop extensive cracking.	Mechanical damage during assembly, excessive compression beyond mechanical limits.	Loss of sealing force, leading to leaks.
Leak Path through GRE	Glass Reinforced Epoxy (GRE) expands and develops microcracks, blistering, and voids.	Inadequate curing of GRE, exposure to process gas causing explosive decompression.	Potential leak path for gas, leading to leaks.
Wrong use of isolation material	Electrical isolation sheet used as both an isolation component and a critical sealing surface.	Design oversight.	Increased potential for leaks.
Material Traceability	Lack of material traceability for forgings and pipes.	Inadequate quality control and assurance.	Difficulty in ensuring material properties and performance, leading to potential failures.
Unintended Short circuiting to ground	The isolation joint is not working properly	The equipment and/or pipeline are earthed so the isolation joint is short circuited	The CP system is not working properly
Operation			
Stray Current Corrosion	Stray currents from cathodic protection systems can cause rapid corrosion at the isolation joint, especially if there is an internal conductive electrolyte.	Lack of internal coating	Increased potential for leaks.
Environmental Factors	Exposure to harsh environmental conditions, such as high humidity or corrosive chemicals, can degrade the materials used in the isolation joint.	Poor design and inadequate inspection	External corrosion Increased potential for leaks.
Internal coating damage	Current bridging resulting from internal coating damage,	Caused by scraping pig operations or coating abrasion when sand production accompanies the produced fluid.	Increased potential for leaks.
Structural threat	External mechanical forces resulting in physical damage to the isolation joint.	Bending stresses or vibrations	Increased potential for leaks.

6 References

/1/ Recommended Failure rates for Pipelines. DNV report 2017-0547 rev. 2 2017-12-08

/2/ Previous editions of this report:

- Recommended Failure rates for Pipelines. DNV report 2009-1115 rev. 1 2010-11-16
- Feildata for rørledninger, DNV report 2005-1221, rev. 4, issued 2006-09-04
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- Feildata for rørledninger, DNV report 91-3387, rev. 1, issued 1992-02-18
- Feildata for rørledninger, DNV report 88-3301, rev. 1, issued 1988-09-22

/3/ PARLOC 2020 Seventh edition, Energy Institute, December 2024

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APPENDIX A

Manufacturing processes and potential errors

A.1 Manufacturing methods

In general, two main manufacturing methods can be identified, seamless pipes and pipes with a longitudinal weld. This appendix will only discuss these types of manufacturing methods. Other types, includes e.g. helical welded pipes, these are however not included in these discussions. Previously, longitudinal welds introduced variations in the ovality of the pipe, with improved production process and control of dimensions and use of automated laser systems for controlling ovality, this is however currently not regarded as a major issue. The use of longitudinal welds introduces possibilities for defects in the weld itself, these welds are however performed as part of multiple productions with a relatively high frequency of production testing of the base and weld material, and with approved and tested weld procedures under controlled circumstances. The frequency for failures related to these longitudinal welds is therefore by experience proven to be low. The possibilities for having a controlled and well-defined welding environment, and for non-destructive testing of the material, are more favourable for rolled and welded pipes than for seamless ones.

Using seamless pipes eliminates the failures related to the longitudinal weld. The use of seamless pipes has increased over the last decades and the technology for manufacturing has developed rapidly because of the increased demand. Previously, only small diameter pipes were manufactured as seamless but today, pipes up to 20” and even up to 24” for some pipe mills, are being produced with seamless technique. Seamless pipes compared to longitudinal welded pipes do however show increased rates related to failures derived from the actual manufacturing since the volumetric inspection by ultrasonic testing of a seamless pipe is more complicated to inspect than the plates prior to the rolling.

A relation between failure frequency and both diameter and age can be noted, but it is rather the year of manufacturing than the actual age or operating hours that has got impact on the failure frequency. Pipelines manufactured in the 1980’s and earlier have stronger negative correlation between failure frequencies and diameter than pipelines produced more recently. Line pipes manufacturing has from the 1990’s and later seen a large improvement in properties of the base material, typically plates with improved impact toughness, leaner chemical composition with associated improved weldability and better control of dimension of the manufactured line pipe. The non-destructive testing of the longitudinal weld seam has also been improved with automated ultrasonic testing replacing radiographic testing with higher sensitivity and ability to detect defects.

Several other aspects linked to both diameter and year of production will also cause variations in the quality of the material and the likelihood of installing a pipe with a non-detected errors or defects.

A potential over roll will be larger in terms of relative surface for thin-walled pipelines and constitutes a larger proportion of the total wall thickness. Over rolling the external surface on seamless pipes, and both (internal and external) surfaces on longitudinal welded pipes, will normally be detected and is shown as cracks in the surface. The likelihood of over rolling increases with the degree of roll. Over rolling is more likely to be undetected for seamless pipes than for longitudinal welded pipes. Over rolling can be detected using ultra sonic testing, and for new pipelines this is thus assessed not to be a major issue.

The likelihood for having scales and slags pressed into the material during the rolling is also larger for seamless pipes. The likelihood of having slag does not depend on the wall thickness or diameter of the pipe but for thin-walled pipelines, an embodied piece of slag will relatively speaking constitute a larger part of the wall than for a thick-walled pipe. Slag may be detected in some cases but doing this is more difficult on the interiors of a seamless pipe.

For errors and defects introduced by over rolling or the presence of slag inside the pipe wall, it is more likely to find these at the internal surface of a seamless pipe than at the external surface or at any of the surfaces on a longitudinal welded pipe since the internal surface of a pipe is the most difficult surface to test and inspect during manufacturing.

The likelihood for laminations is proven to be relatively independent of diameter and wall thickness. For thin-walled pipelines, the laminations will however be rolled out over a relatively larger area and at the same time constitute a larger proportion of the wall thickness than for thick-walled pipes. Lamination may in some cases be detected through ultrasonic or x-ray testing. However, laminations are not assumed to be an issue for modern steel making and for line pipes manufactured since 1990's. The detection of possible laminations is also assumed to be high with modern inspection techniques.

During the seventies, problems related to lamination and subsequent stepwise cracking in the pipe were an issue. In an effort to increase the yield stress and tenacity of the material, one introduced a new method of "controlled rolling" of pipe steel, i.e. rolling at lower end roller temperature than done before. Doing so resulted in an unfavourable degree of MnS embodiments with subsequent risk of cracking. Manufacturing methods and material technology are now developed and modified in such a way that the likelihood of having these defects introduced is significantly reduced for pipelines produced after 1980 compared the ones produced during the seventies.

Another failure mechanism linked to seamless pipelines is variations in diameter. The ends are weld points for the adjacent pipe, quality checks of wall thickness and diameter are crucial at these points. There are occasions where the drift shaping the internal diameter and surface moves radial causing the wall thickness to be too large at one part and too small at the diametrically opposite, Figure 6-1.

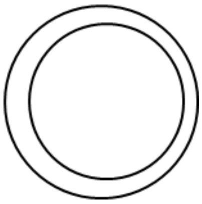


Figure 6-1 Resulting cross sectional shape from a moving drift (schematic).

The reduced wall thickness may be critical with respect to strength and corrosion. The increased wall thickness may be critical with respect to level of tension during lay and installation of the pipeline which could lead to cracks.

Compared to the past, pipes with larger diameter can be produced as seamless pipes, meaning that errors typically linked to seamless pipes today are present for a wider range of diameter than before. Some failure modes that previously have had a strong negative correlation between diameter and failure frequency are now applicable to large diameter pipes as well. However, it cannot be concluded that the likelihood for failure to large diameter pipes has increased over the last decades. This is partly due to the fact that the failure mechanisms typically linked to seamless pipes are more likely to occur and cause failure in thin-walled pipes, i.e. small diameter pipes.

Another reason for that no relative increase in failure frequencies, linked to seamless pipes and diameter, is noted is that the quality checks in steel production has gone through a tremendous development since 1980's. Knowledge of production methods and chemical composition has also increased. In steel pipe production of today, the production with respect to chemical composition and mechanical features are more even than before. Requirements on quality and check procedures have also increased over the years which all together increase the likelihood of the pipe fulfilling requirements on specified properties all along the pipe and along its circumference. The likelihood of having defect welds is therefore also reduced since the weld procedure is tested on a well-defined material which now is very likely to mimic the actual material.

Despite the positive trend in steel and pipe production over the last decades, so called unpredictable failures or sources to failure occur at regular intervals. To some extent, past failure sources tend to reappear after some time, when focus on preventive actions is decreased as the specific failures disappear. One should also be aware of the fact that regardless of the level of quality management and monitoring one can never completely eliminate the likelihood of having human or equipment failures resulting in the installation of a defect pipe.

Another important issue from the last decades of development is the production and application of more high tensile steel. As a result of the increased competence and knowledge about the production process one now produces steel pipes that are highly dependent of having the important parameters within strict margins. Deviations from the production parameters are more likely to have severe consequences for pipes of modern high tensile steel than for pipes made out of older types of steel. E.g., from a chemical point of view, modern steel has a reduced likelihood of brittle fracture. However, this property is linked to the microstructure of the material and in some cases a correct heat treatment. If the heat treatment is faulty carried out, the impact on the likelihood of having brittle fractures at low temperatures is significantly increased, however, this is not considered an issue of modern line pipe manufacturing due to strict control of production and a relatively high frequency of mechanical testing. Such faults may also appear locally if ovens or the cooling process equipment won't ensure a uniform environment throughout the whole pipe wall and all along the pipe.

The likelihood of having a faulty heat treatment does not depend on the diameter of the pipe. Such mistakes or errors may occur independently of the quality of material and dimension. For larger wall thickness, there is however an increased likelihood for variations in the heat treatment cycle in the radial direction. The consequence of such an error will in general increase with the steel tensile strength. Faulty or inadequate heat treatment of high tensile steel normally has larger impact on the material property than in the case of steel with lower tensile properties. Increased tensile strength could also contribute to increased likelihood of stress corrosion.

The quality and strength of the material can to some extent be related to the diameter and wall thickness of the pipe. Using high tensile steel will enable the use of pipes with smaller wall thickness given that operational conditions are identical. Doing so will increase the likelihood for a number of other failures causes typical for thin-walled pipes.

Since there is an increasing trend of using high tensile steel for pipes and the production methods of seamless pipes are constantly developing, it is reasonable to believe that previous recorded differences in failure frequencies due to variations in pipe diameter will be less significant. Other parameters, such as wall thickness, manufacturing method and steel quality should be evaluated in order to reach a reliable estimate on reliability and failure frequencies for newer pipelines. For older pipelines, year of production should be taken into account when establishing the corresponding failure frequencies.

A.2 Welding

Defective welds are found both among the longitudinal welds (where applicable) and in the girth welds, i.e. joints connecting the individual line pipes. The likelihood for having defective welds generally depends on a number of factors such as the material used, weld procedures, and weld execution. The most important factors affecting the likelihood for defective welds are:

- The chemical composition of the steel and its associated weldability. Since 1990's the purity if the steel and the weldability have in general improved.
- Welding parameters and the setup of the welding equipment to ensure that consistent weld quality is achieved.

Developing weld procedures includes evaluating several factors essential to achieve a weld with a minimal level of defects. This task is most complex for high strength steels and complex for some stainless steels. For these steels, deviations from the weld procedures are more critical than for other steels.

There are several aspects that influence the quality and integrity of the weld. The main aspects are listed below:

- Added material. The added material is normally chosen so that the strength slightly exceeds that of the pipe material. The properties of the weld and pipe metal should as to the rest be matched in the best possible way. Large differences in chemical composition could result in potential gaps, resulting in galvanic corrosion.
- Geometry of the seam. A narrow seam is more efficient compared to a wide seam in the sense that less material is required to fill the groove. However, a narrow seam increases the likelihood for hot cracks due to tension, and detection of lack of fusion and slag along the seam is more complex in case of steep seam edges.

- Cleaning of the weld between welding runs. Effective cleaning of weld seams prevents formation of slag and pores.
- Heat input. The heat input is essential in the weld procedure. The heat cycle which the weld and the heated area around the weld is exposed to defines the microstructure, which in turn defines the hardness, toughness properties, strength and residual tension. Large heat input results in high tension after cooling, which affects the likelihood for hot cracks, stress corrosion and hydrogen embrittlement.
- Gas supply. A stable and clean gas supply is essential to avoid formation of pores and impurities in the weld.
- Heat treatment. Heat treatment could be used to reduce the level of tension in the weld and to reach desired microstructure and hardness. The heat treatment must be carried out within a certain amount of time after the completion of the weld to avoid letting hydrogen embrittlement and cracks develop.
- Testing. The weld procedure needs to be tested and qualified to confirm that the weld will withstand the conditions relevant during operation. Except for some load tests, this is done when testing is performed in accordance with prevailing standards. There is also a requirement to perform production testing for the installation welding, but the frequency of production test is very limited, for most projects limited to one test per procedure. Hence, the quality and follow up of the welding procedure qualification is critical.
- Inspection of the weld. For pipeline installation welding, there is much attention to the non-destructive testing of welding and this is typically done with automated ultrasonic testing (AUT) that is developed and validated particularly for each weld configuration. The development of the AUT in the last decades have improved the quality of volumetric inspection of the girth weld and is of much higher quality and higher sensitivity of detecting defects compared to the radiographic testing that was done in the 1980's and earlier.

The welding must be carried out in accordance with the developed procedure and within the specified parameters. The external conditions differ depending on whether the welding is productional or procedural. It is likely that conditions are more favourable or easier to control and monitor during a procedural weld compared to a productional weld. When developing the weld procedure, this must be considered so that the conditions required by the procedure are realistic and achievable. Exclusion of moist during the welding is one of several essential factors. Adequate physical coverage to prevent wind disturbances to the gas coverage is another important factor. Achieving adequate welds are easier for the longitudinal seams carried out in a controlled environment during production of the line pipe, compared to butt joints welded during lay.

The most frequent errors and defects for pipeline girth welds are:

- Hydrogen cracks / hydrogen embrittlement. This error could develop when hydrogen is present and there is a critical microstructure and sufficient tension. High tensile steels are more prone to this error than most other steels. The likelihood for error also depends on geometry, heat supply, heat treatment and weld execution. Hydrogen embrittlement affects the material toughness locally. Compared to other weld error, this error is a common phenomenon.
- Hot cracks due to tension. Arise in the melted zone or heat affected zone during cooling. The likelihood depends on chemistry, geometry and level of tension.
- Lack of fusion. Caused by insufficient melting in the melting line or between welds. The likelihood depends on choice of heat supply.
- Pores / inclusions / slags. Caused by impurities in the material, seam or gas. The likelihood primarily depends on cleaning and gas coverage.

- Faulty or unfavourable geometry. Affects fatigue properties. Depends on design (geometry / local tension) and execution.

A weld represents an inhomogeneity and therefore increases the likelihood for local corrosion. Remaining stress in the weld increases the likelihood for stress corrosion. Remaining stress is normally largest for high tensile steels and depends on heat transfer and treatment. Variations in microstructure and chemical composition cause local variations in potential and thereby a slight increase in likelihood for galvanic corrosion. This could cause corrosion either in the melted zone or in the heat affected zone, depending on conditions.

In general, the longitudinal welds do not significantly contribute to failures as long as they are carried out under monitored and well-defined conditions. Relatively, pipeline girth welds represent a larger source of failure, both for seamless pipes and longitudinally welded pipes. The likelihood for faulty welds depends on routines for quality control, control and monitoring of the welding itself and non-destructive testing after completion. The use of high tensile steels contributes to a significant increase in likelihood for welding errors.

APPENDIX B
Causal relations for pipeline failures

B.1 Causal relations for pipeline failures

Table B.1 gives an overview of causal relations that can result in failures on a pipeline. This table was included to this report in the 1997 revision. The table has not been revised as part of the latest revision update. It is however assessed that causalities identified and listed in the table are still relevant.

The failure mechanisms are divided into general groups that coincide with the groups that are found in the various data sources (see report chapter 4):

- Corrosion
- Third party activity
- Production
- Material and components
- Weld
- Operation & maintenance
- Environment

An assessment of the distinction between defects and failures were not made. Only the most probable extreme consequence for a failure were considered.

For additional explanation, short comments are given for some of the causes. An assessment of relevant references for different causes were also performed. This was done to investigate the matter that failure frequencies in general are reported per km, while this may be too conservative for long pipelines.

The causes listed in Table B.1 has not been ranked.

Table B. 1 Causal connections for failures on pipeline

	Cause				Mechanism	Defect	Failure (extreme consequence)	Comment	Unit
	Description[20]	D	P	O					
Corrosion	Unwanted (extra) water in the process. (Can be monitored).			x	Internal corrosion	Loss of wall thickness (local pitting or uniform corrosion)	Leak	Effect from undesired water in the process has to be inspected. Continuous corrosion can be reduced by using inhibitor.	per pipeline
	Bad water during water filling		x		Internal corrosion	Loss of wall thickness	Leak	Uncertain whether corrosion stops if the pipeline is dried before use.	per pipeline, or per water filled section
	Not enough/no inhibitor (can be monitored)	x		x	Internal corrosion	Loss of wall thickness	Leak	The amount of inhibitor can be increased after an inspection has identified the problem. Recurring inspection is necessary to document the effect.	per pipeline
	Wrong steel material	x			Internal corrosion	Loss of wall thickness	Leak	Choosing regular carbon steel instead of stainless	per pipeline
	Welding, welding procedures							See detailed section for welding failures	
	Wrong corrosion coating (offshore)	x			External corrosion	Consumption of anodes	-	New anodes can be installed later	per pipeline
	Damage to corrosion coating, during construction or through impact (offshore)		x	x	External corrosion	Consumption of anodes, damage to coating	-	New anodes can be installed later, new coating can be applied	per area
	Damage to corrosion coating, during construction or through impact (riser)		x	x	External corrosion	Loss of wall thickness, damage to coating	Leak	Anodes only help under water, new coating has to be applied to stop corrosion.	per riser

20 Cause related to the following phases: D – Design, P – Production (includes everything from production of the steel to installation and completion), O – Operation

	Cause				Mechanism	Defect	Failure (extreme consequence)	Comment	Unit
	Description[1]	**D**	**P**	**O**					
	Damage to corrosion coating (onshore)		x	x	External corrosion	Loss of wall thickness	Leak	Damage can be fixed (does this stop the corrosion?)	per area (or km)
	Wrong corrosion coating (offshore)	x			External corrosion	Loss of wall thickness	Leak	Effect from flow pressure must be documented (CP measures). Higher flow pressure may help.	per pipeline
	Not enough flow pressure (onshore)	x			External corrosion	Loss of wall thickness	Leak	Amount of flow can be adjusted after discovering corrosion. The effect has to be documented through recurring inspection.	per pipeline
	Too high flow pressure (onshore)			x	Hydrogen induced cracks	Crack	Leak (full rupture)	May lead to hydrogen embrittlement and cracks.	per pipeline
	To high flow pressure (onshore)			x	Stress induced corrosion	Crack	Leak (full rupture)	May lead to hydrogen embrittlement and cracks. Increases with higher steel quality (problem over X70) and presence of hydrogen?	per pipeline
	To high flow pressure (onshore)			x				May damage coating, and thereby increase the possibilities for corrosion.	per pipeline
	Erosion			x	Erosion	Loss of wall thickness	Leak	Requires the presence of sand.	per bend or per valve
Extreme accidental load	Collision with ship (riser)	x		x	Impact load	Denting/hole in pipe wall	Leak	Ships traffic close to riser can be restricted and monitored. Damage to coating may initiate external corrosion.	per riser
	Collision with ship (pipeline) 1. Ship running aground close to the shore 2. Sinking ship	x		x	Impact load	Denting/hole in pipe wall	Leak	Can not be monitored or limited satisfactory. Protection against run around through additional burying, dumping of rocks etc. Damage to coating may initiate external corrosion.	per area with regular shipping traffic
	Collision with train, cars etc. (onshore)	x		x	Impact load	Denting/hole in pipe wall	Leak	Same as over	per area with regular traffic

	Cause				Mechanism	Defect	Failure (extreme consequence)	Comment	Unit
	Description[1]	D	P	O					
	Construction activity nearby (offshore)	x		x	Impact load	Denting/hole in pipe wall	Leak	Can be restricted and monitored. In general, construction activities offshore are few, limited, carefully planned and involves the relevant parties. Damage to coating may initiate external corrosion.	per operation and area (or pipe)
	Construction activity nearby (onshore)	x		x	Impact load	Denting/hole in pipe wall	Leak	Might be restricted. There can be a lot of construction activities onshore, and the communication between the relevant parties is not always satisfactory. Damage to coating may initiate external corrosion.	per km (or area)
	Fishing (trawling)	x		x	Impact load	Denting/hole in pipe wall	Leak	May include capacity against fishing activities in the planning phase, e.g. bury small pipelines. Reported failures relates to small pipelines that are not buried.	per area with fishing activity
	Dropped objects from platforms	x		x	Impact load	Denting/hole in pipe wall	Leak	May include a certain capacity against dropped objects in the planning phase, e.g. bury or protect through constructions.	per area close to platform
	Falling anchorage (dragged anchor chains)	x		x	Impact load	Denting/hole in pipe wall	Leak	Can be limited and monitored close to platform. Can not be limited or monitored in general. Anchoring (also emergency anchoring) only real close to shore or platform. Maybe possible to include capacity against anchorage in the planning phase, e.g. additional burying, dumping of rocks, etc.	per area close to platform or area with regular shipping traffic
	Vandalism/Terrorism/Actions of war	x	x	x	Impact load	Hole in pipe wall	Leak	Can not be limited	per pipeline
Production	Welding, welding procedures							See detailed welding section	
	Incautious treatment of pipelines during transport and storage		x		Impact load	Increased ovality	Collapse of cross-section	Can be measured before installation	per pipe section

	Cause				Mechanism	Defect	Failure (extreme consequence)	Comment	Unit
	Description[1]	D	P	O					
	Incautious application of coating, wrong coating type	x	x					May initiate corrosion	per pipeline
	Too high installation loads		x		Extreme bending	Increased ovality	Collapse of cross-section	Damaged piece has to be removed before the pipeline can be used. Extent of damage can be reduced through use of bulge-stoppers.	per x m (with bulge-stoppers)
	Too high-pressure testing		x		Rupture	Fracture	Leak		per pipeline
	Damage from burying and filling		x		Impact load	Denting/ increased ovality	Leak	Can be inspected. May occur as a result from using wrong equipment for relevant soil type. Damage to coating may initiate corrosion.	per pipeline/area with difficult soil type
Material & Components	Sealed surfaces badly jointed		x	x			Leak	Discovered through pressure testing.	per comp.
	Brittle material when cool down as a result of choking of gas pressure	x		x	Rupture	Crack	Leak	In addition to the material being brittle, there has to be another load (i.e. blow) present to initiate a failure.	per pipeline
	Over rolling		x		Fatigue	Crack	Leak	Probability and extent relative to wall thickness increases with roll degree, can be detected from the surface.	per pipeline
			x		Reduced statically strength	Crack	Leak		
	Embedded slag		x		Reduced statically strength	Crack	Leak	Extent relative to wall thickness increases with roll degree, can be detected from the surface.	per pipeline
			x		Fatigue	Crack	Leak		
			x		Corrosion	Loss of wall thickness	Leak		

	Cause				Mechanism	Defect	Failure (extreme consequence)	Comment	Unit
	Description[1]	D	P	O					
	Lamination		x		Reduced resistance against tearing in connection with welding	Crack	Leak	Probability and extent relative to wall thickness increases with roll degree, can be detected through ultrasound.	per pipeline
	Insufficient/wrong heating treatment		x		Reduced strength	Rupture	Leak	Most relevant for high tensile steel	per pipeline
			x		More brittle	Crack	Leak		
	Non-roundness/insufficient thickness		x		Reduced strength	Bulging	Leak	The end pieces can be measured, but variations may occur in the length direction	per pipeline
	Chemistry not according to specification. Increased probability for jointing in connection with welding.		x		Fatigue	Crack	Leak	Can be detected after welding	per pipeline
Weld	Pores / embodied slag		x		Corrosion	Loss of wall thickness	Leak	Dependent on welding execution, the most serious can be detected (for steel)	per weld
					Reduced strength	Burst	Leak		
					Fatigue	Crack	Leak		
	Coagulation fractures / Lamination fractures		x		Fatigue	Crack	Leak	Dependent on tensions and the local chemistry of the base metal, can be detected	per pipeline
	Geometry failures / unfortunate geometry	x	x		Fatigue	Crack	Leak	Dependent on design and execution	per weld
	Hydrogen-brittleness		x		Reduced strength	Rupture	Leak	Non-detectable if there is no fracture, highest probability for high tensile steel, also dependent on execution/procedure	per pipeline
			x		Fatigue	Crack	Leak		
			x		More brittle	Rupture	Leak		

	Cause				Mechanism	Defect	Failure (extreme consequence)	Comment	Unit
	Description[1]	D	P	O					
	Wrong procedures	x			Multiple		Leak	Should be avoidable through procedure testing of the right material	per weld
Operation & Maintenance	Poor pressure monitoring			x	Rupture	Crack	Leak		per pipeline
	Not enough inhibitor			x	Waxing/ Hydrate-formation	Smaller inner diameter	Stop		per pipeline
	Too low temperature			x	Waxing/ Hydrate-formation	Smaller inner diameter	Stop		per pipeline
	Too low temperature			x	Condensation			Precipitation of water, leading to corrosion Wrong insulation coating may lead to too low operation temperatures.	per pipeline
	Large and frequent pressure variations			x	Fatigue	Increased cracking	Leak		per pipeline
	Large and frequent temperature variations			x	Fatigue	Increased cracking	Leak		per pipeline
	Upheaval buckling (thermal expansion)	x	x	x	Extreme bending	Increased ovaling	Collapse	May come as a result from failures during the design phase, insufficient burying or too high temperatures. Normally only pipes smaller than 16” are buried.	per pipeline (buried)
	End-expansion (thermal expansion)	x	x	x	Extreme bending	Increased ovaling	Collapse	Can come as a result from bad design, bad installation in addition to too high temperatures	per end piece
	Lateral buckling (thermal expansion)	x	x	x	Extreme bending	Increased ovaling	Collapse	Same as over, but may also occur for larger diameters	per pipeline
	Hot-tapping			x		Hole	Leak		per operation
Environment	Storm damage			x	Multiple		Leak	Relevant storm criteria shall be included in the design phase	per pipeline
	VIV			x	Fatigue	Increased cracking	Leak		per span

	Cause				Mechanism	Defect	Failure (extreme consequence)	Comment	Unit
	Description[1]	D	P	O					
	Wave loads on riser			x	Fatigue	Increased cracking	Leak		per riser
	Foundation washed away			x	Fatigue	Increased cracking	Leak		per span
	Foundation washed away			x	Extreme bending	Increased ovaling	Collapse		per span
	Earthquake			x			Leak		per area
	Landslide			x			Leak		per area
	Sinking into the ground			x			Leak		per area

APPENDIX C
Unintentional anchor drops from ships in transit

C.1 Introduction

There are incidents where pipelines or cables are hooked and damaged by anchors from ships in transit. This appendix suggests the frequency for failure to pipelines due to uncontrolled anchor drops with subsequent dragging, per ship crossing, as function of:

- Pipe diameter,
- Ship size, and
- Pipeline protection philosophy.

Focus is limited to the dragging of the anchor and not the potential impact from the actual anchor drop. This part of the report was particular in focus in the 2010 edition /2/. For this and the previous (2017) edition of the report this approach together with the basic assumptions regarding damage criteria, anchor design and drop scenarios has been kept unchanged. The frequencies have been updated based upon updated anchor loss statistics only. Updated anchor loss statistics show however very little change in drop frequency and the updated frequencies are therefore very similar with the earlier editions of the report.

C.2 Approach

When the number of incidents is large and the population is well defined, failure frequencies are often estimated mainly based on empirical data. For incidents resulting in damage to pipelines due to anchors dragged by ships in transit, the number is currently too small to establish reliable failure frequencies for different pipeline diameters.

Instead of only studying the actual number of recorded damages to pipelines due to uncontrolled anchor drops, the frequency for uncontrolled anchor drops has been estimated based on data on lost anchors recorded by DNV surveyor records. The process of transforming the number of lost anchors per year into actual failure frequencies for the pipelines has been a combination of quantitative and qualitative analysis.

Areas given special attention due to their impact on the result are:

- Ship: Speed, Displacement (Mass).
- Anchor: Dimensions, Chain length, Chain strength, Bitter end strength, Penetration depth.
- Soil.
- Water depth.
- Pipeline load resistance.

C.3 Scenario

The scenario of concern is a ship that, while in transit, for some reasons deploys one of its anchors. To understand what can trigger such a situation, a brief description of a ship's anchor winch and related routines is included below.

The anchor winch is used to pay out and haul the ship anchor. The winch itself can be of hydraulic type and is generally equipped with a band brake. There are also a chain lock and a chain stopper (turnbuckle), see Figure C.1.

When the ship is at anchor, the chain lock is used to secure the chain and to take the load from the winch. The chain stopper is not used. When the anchor is hawsed (i.e. in secured position at ship), the chain stopper is applied and tightened. At this point, there is no load to either the winch or the applied chain lock, but the band brake should nevertheless be applied. Other designs on anchor winch and chain arrangements can also be found.

Based on actual findings, there is a concern that the chain stopper with its hook is not always in a good condition or is not correctly applied. In bad weather when there is movement both in the ship and the anchor, snatches may cause the chain stopper to break or jump. Since there is no load in the part of the chain between the winch and the chain stopper, a braking chain stopper would cause a jerk in the chain. Since the chain lock is primarily used for securing the chain while the ship is at anchor, it cannot be said for sure that the lock is always applied in an adequate way while the ship is in transit. There are numerous recorded incidents involving unsatisfactory maintained or dysfunctional band brakes (ref. /C-37/) from related industries, meaning that a band break will not necessarily be able to stop a free-falling anchor.

When the ship approaches port or navigates through narrow passages, the anchor is prepared for quick drop, meaning that both the anchor stopper and chain lock is removed. This is done to minimise the time from a possible machinery or steering failure to initiated emergency anchoring. Since the anchor then only rests on the band break, there is an increased likelihood for uncontrolled anchor drop.

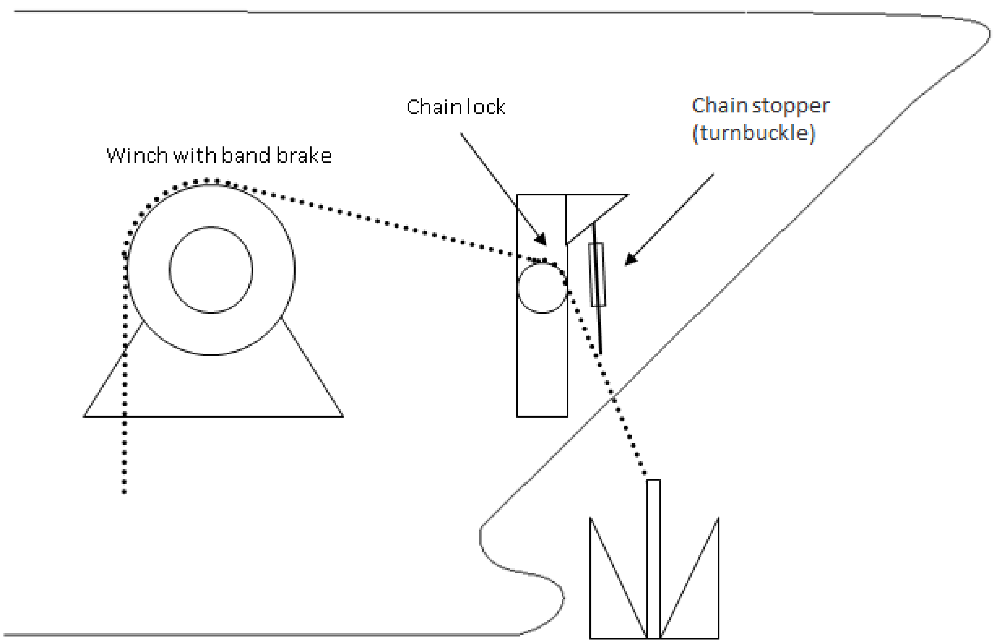


Figure C.1 Explanatory sketch of anchor winch arrangement

After having unintentionally dropped the anchor while in transfer three alternative sequences and outcomes are considered relevant, see Figure C.2. The potential for impacting subsea pipelines or similar on the seabed will only be possible if the length of the anchor chain exceeds the water depth.

In addition to manned ships there are also ships and barges being towed. There is a concern that the likelihood for unintentional anchor drops from such ships/barges is higher than for manned ships in transit. One reason for the concern is that the towed ship or barge may be unmanned, increasing the likelihood for the drop to remain undiscovered. Another reason is that some of the ships being towed are towed to distant yards for scrapping. The condition and technical integrity of such ships including equipment for anchoring can be expected to be significantly worse than for ships registered for traffic. On the other hand, for general shipping lanes the number of towed ships and barges is small compared to other traffic. In areas where the number of towed ships and barges is significantly larger than what is common elsewhere (outside scrap yards etc.) a detailed analysis is recommended. The probabilities given in Figure C.2 are set based on experience for the three outcomes as described below.

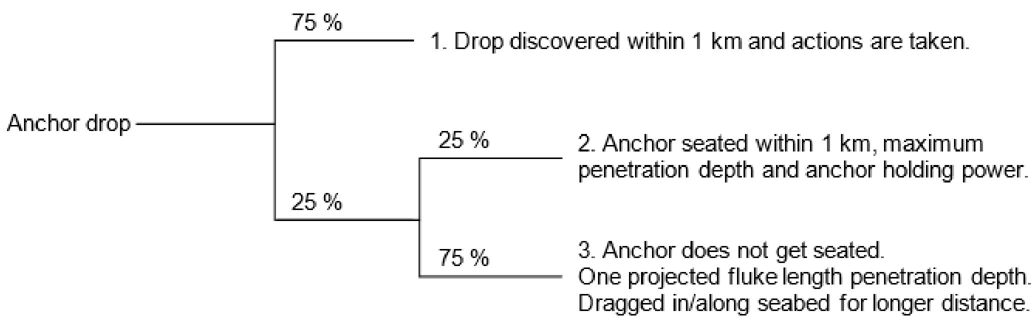


Figure C.2 Event tree for the case uncontrolled anchor drop

C.3.1 1st outcome - Drop is discovered within 1 km

It is assumed to be more likely that an uncontrolled anchor drop is discovered within a relatively short distance than not. The assumption is based on the following influencing factors[21]:

- \+ Noise - Paying out an anchor chain will cause noise (on some ships, the distance between the anchor and the bridge may however be considerable)
- \+ Vibrations - Paying out an anchor chain will cause vibrations to hull and possibly the bridge
- \+ Velocity - The force from a dragged anchor will affect both speed and manoeuvring ability of the ship.
- \- Weather - It is likely that the uncontrolled drop occurs in bad weather when there is extra movement in both ship and anchor. Bad weather has a reducing effect on the positive factors above.

In this scenario the anchor will not reach maximum penetration depth and therefore no anchors are assumed to be lost due to holding power exceeding the chain strength or bitter end arrangement. Nevertheless, the anchor may be able to hook a pipeline, in particular if the pipeline is exposed or flush with the seabed.

C.3.2 2nd outcome - Anchor seated

Whether the anchor settles or not is a complex matter which depends on many factors such as speed of ship, length of anchor chain, water depth, size of anchor, type of anchor and soil characteristics. Assuming the anchor will only in a minority of cases (1/4) get seated is considered a conservative estimate.

Assuming the parameters related to anchor size and chain length will enable hooking, all three outcomes may result in pipeline hooking. However, in this and in the first outcome the anchor is dragged for a relatively short distance (1 km), and thus the likelihood of hooking and damaging a pipeline is low compared to the third outcome.

Looking closer at outcome 2, it is not obvious that a ship in transit with an anchor settling into the seabed will cause chain or bitter end breakage. This outcome has therefore been studied in more detail. If the anchor is fully seated and reaches both its maximum penetration depth and holding power, there is a chance that the anchor may be dragged at maximum penetration depth over a distance longer than 1 km (outcome 3).

21 “+” / “-“ indicates increased / decreased likelihood.

C.3.3 3rd outcome - Anchor not seated

For the third outcome, it is assumed that the anchor is not seated and can be dragged over a longer distance without being discovered (ref. outcome 1) and without holding power exceeding the chain break and bitter end break load (ref. outcome 2).

Due to the low holding power, it is assumed that the anchor penetration depth is limited to one projected fluke length. This outcome is the most critical in the sense that the anchor will be dragged undiscovered over long distances, and thereby poses serious threats to pipelines and cables.

C.4 Damage criteria

Dragging an anchor towards a pipeline will require several conditions to be fulfilled in order to actually cause damage. This chapter presents the criteria deemed relevant for causing damage to pipelines of different diameter and protection. Issues covered are:

- Water depth related to anchor chain length.
- Projected fluke length.
- Anchor penetration depth.
- Applied load forces from anchor related to: Anchor chain break load, and force and energy from ship.
- Pipe load resistance depending on: Pipeline diameter, Protection philosophy, Soil.

Dependent on the ship's displacement and geometry a vessel equipment number (EN) is calculated. EN is a dimensionless parameter, and for each EN there are specific requirements for onboard equipment such as anchors and anchor chains (ref. /C-38/). When studying traffic data and statistics, equipment number may however be difficult to retrieve, therefore an approximate relationship between ship class, displacement, gross tonnage (GRT), and equipment number[22] has been used in this analysis. A table with this approximate link, inclusive anchor mass and anchor chain length is given in Table C.1.

Table C.1 Approximate relationship between ship class, displacement, GRT, equipment number, length of anchor chain and mass of anchor /C-38/, /C-41/

Class	Displacement [tonnes]	GRT from	GRT to	Equipment number from	Equipment number to	Length of anchor chain[23] [m]	Anchor mass [kg]
I	1500	100	499	280	320	193	900
II	3600	500	1599	450	500	220	1440
III	10000	1600	9999	980	1060	248	3060
IV	45000	10000	59999	2870	3040	330	8700
V	175000	60000	99999	5800	6100	385	17800
VI	350000	100000	-	8400	8900	385	26000

22 The classes defined here represents only a few equipment number (EN) ranges. Significantly more categories could be defined. The selection is however assessed to provide a good representation of vessel sizes.

23 The length of one anchor chain is half the total anchor chain length (assuming two anchors per vessel). The anchor chain lengths are in multiples of 27.5 m. If the total chain length is an odd multiple of 27.5 m, then the half-length is rounded up to the nearest multiple.

C.4.1 Water depth and anchor chain length

This analysis suggests a conservative philosophy when relating water depth to chain length. If a ship moving forward at very large water depth suddenly loses one of its anchors, the anchor will not be hanging vertically down from the hawse. The anchor and the belonging chain will be forced astern by the interaction between anchor / chain and the seawater. This fact causes the relation d/l in Figure C.3 to be less than one, meaning that the anchor chain length needs to be larger than the water depth for the anchor to reach the seabed.

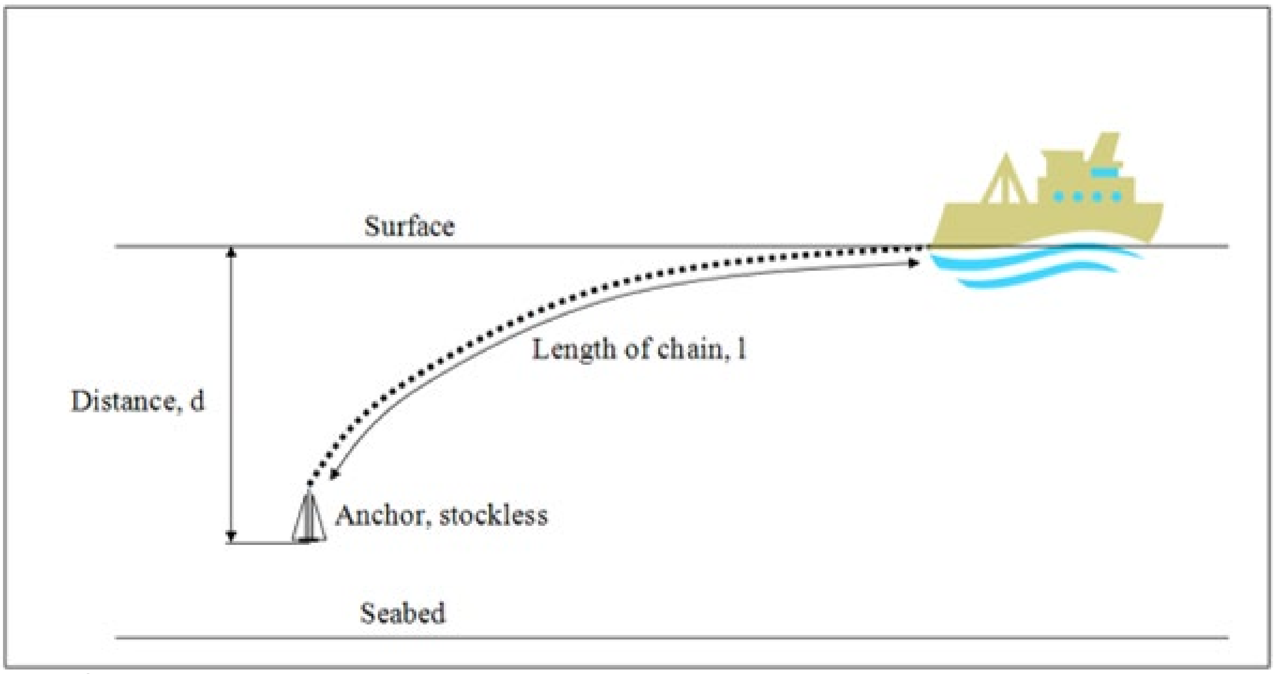


Figure C.3 Explanatory sketch towed anchor

Estimating reliable relations between d and l has been proven difficult since ships within the same ship class have varying speed. Even though the relations between ship size, anchor size/mass, chain size/mass/length are well defined (/C-38/ /C-42/), the large variations in ship speed within one and the same ship class will cause large variations to the relation d/l making such estimates unreliable. Therefore, this guide suggests using a conservative relation between d and l equal to one. This is assessed to be conservative since it is highly unlikely that the anchor will be able to penetrate fully into the seabed if it barely reaches the seabed.

Ships crossing the pipeline where the water depth exceeds the chain length should not be accounted for in the final frequency estimation of damage to the pipeline.

C.4.2 Projected fluke length and pipeline diameter

The following criterion describes the requirement for a stockless anchor being physically able to hook a pipeline:

- Projected fluke length $C_{\perp} \geq d/2$, where;
- $C_{\perp} = C \times \sin \alpha$
- C = Length of fluke
- α = Angle between fluke and shank, max 45° for stockless anchors
- d = Outer diameter of steel pipe (excluding coating)

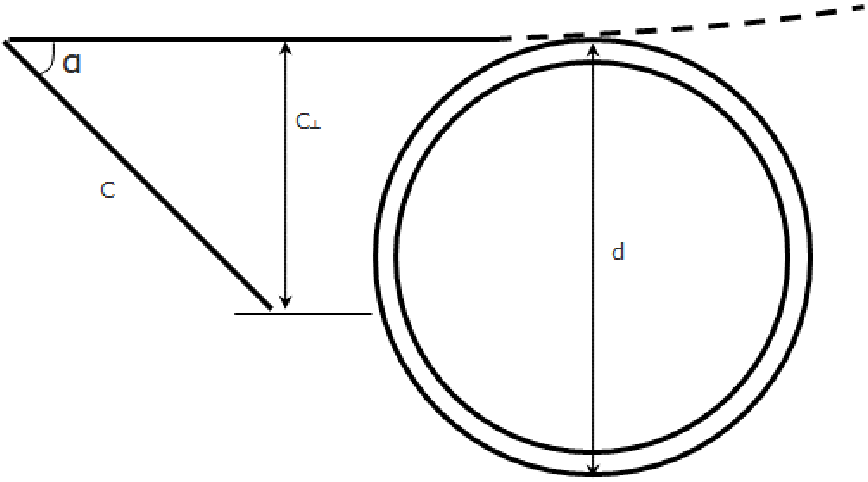


Figure C.4 Size of anchor related to pipeline diameter

The diameter of the pipeline is chosen without taking the coating into account since this might be damaged by the dragged anchor chain. The length of the flukes is related to type of anchor and the mass of the anchor which in turn is related to ship characteristics (i.e. ship class defined in Table C.1). In Table C.2, a worst-case angle α of 45° has been chosen. Anchors used in this analysis are of stockless type.

Table C.2 Relationship between ship size, anchor mass and fluke length for stockless anchors

Class	Anchor mass [kg]	C, fluke length [m]	C⊥, Projected fluke length [inches]	C⊥, Projected fluke length [m]
I	900	0.84	23.4	0.60
II	1440	0.91	25.3	0.65
III	3060	1.26	35.1	0.89
IV	8700	1.83	50.9	1.30
V	17800	2.31	64.3	1.64
VI	26000	2.64	73.5	1.87

C.4.3 Anchor penetration depth

For a trenched pipeline to be hooked by an anchor, the penetration depth of the anchor needs to be sufficient for the fluke to hook the pipeline. Two different studies including anchor fluke penetration depth in seabed have been used to estimate anchor penetration depth. The first one, performed by AT&T and Alcatel /C-44/ applies data from NCEL /C-39/ and expresses penetration depth as multiples of fluke lengths for two kinds of soil. The other study based on practical centrifugal tests carried out at the University of Western Australia /C-43/ suggests a similar penetration depth, given in multiples of fluke length:

- Other anchor types than stockless anchors may be used within the shipping industry, but the stockless type is the most common one.
- Hard soil refers to sand / hard clay and soft soil refers mud / soft clay respectively.

This study has not considered potential effects from backfilling / dumping of rocks over the exposed or trenched pipeline. Such actions may cause the dragged anchor to raise and potentially slide over the pipe.

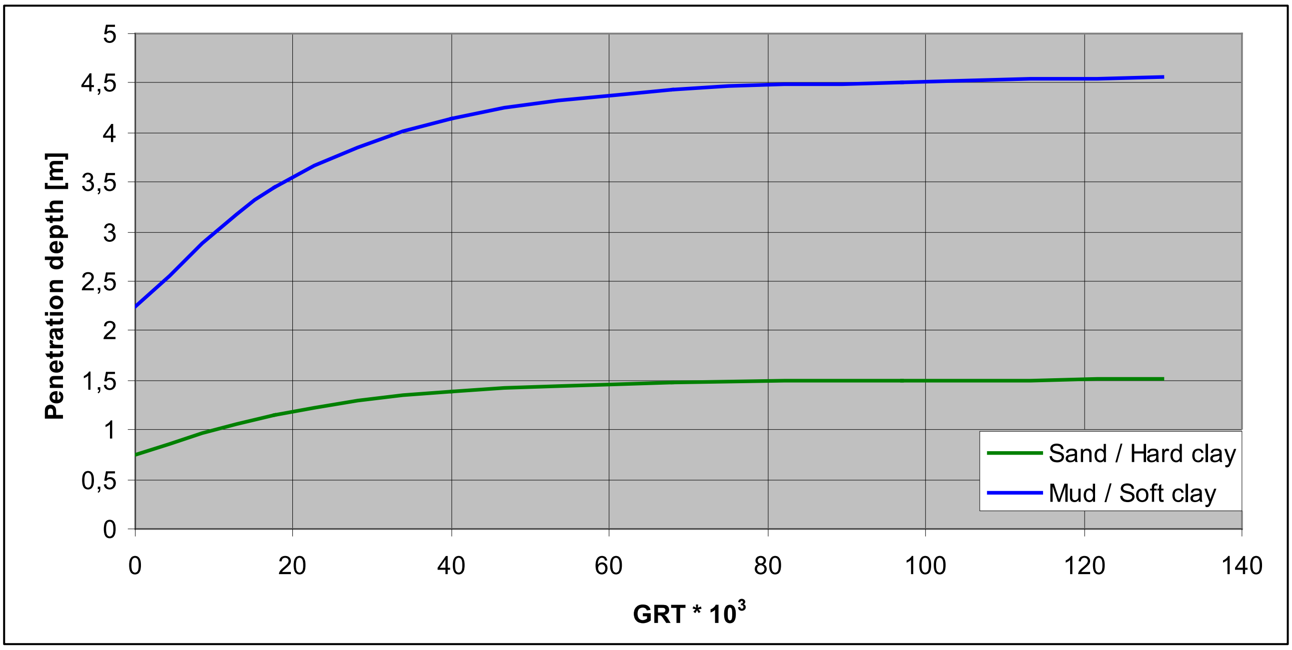


Figure C.5 Anchor penetration depths for stockless anchors depending on soil and size of ship

Table C.3 Estimated anchor penetration depths for seated anchors

Class	GRT	Fluke length [m]	Penetration depth [m] Hard Soil	Penetration depth [m] Soft Soil
I	100 – 499	0.84	0.60	1.79
II	500 – 1599	0.91	0.65	1.94
III	1600 – 9999	1.26	0.89	2.68
IV	10000 – 59999	1.83	1.30	3.89
V	60000 – 99999	2.31	1.64	4.91
VI	> 100000	2.64	1.87	5.62

C.4.4 Load from anchor

It is reasonable to assume that if the force originating from the ship's thrust is sufficient to cause damage to the pipeline, the thrust force can be used as the applied external load to the pipeline rather than the load derived from the retardation of the ship when hooked to the pipeline. However, especially for the larger pipelines (typically ≥ 32") and midsized ships, there are cases where the thrust force is smaller than the pipe load resistance and the chain break load is larger than the pipe load resistance. Even though the thrust force is smaller than the load resistance, it cannot be concluded that the pipe will suffer no damage since the ships kinetic energy will be transferred to a force as the ship retards. Therefore, a contribution from the force from kinetic energy has been added to the thrust force to reflect the actual load for theses specific cases.

The force from the retarding ship has been roughly estimated through fundamental relationship between kinetic energy and force depending on the distance required to bring the ship to a stop. That distance is set to the lateral displacement causing inacceptable strain, meaning that if the force required to bring the ship to a stop is larger than the force resulting in inacceptable strain, the pipeline will suffer damage. Equally, if that distance is exceeded, the pipe will suffer damage due to inacceptable strain as a result from the increased lateral displacement. Strain and lateral displacement are further discussed in chapter *Damage due to strain*. The relationship between ship thrust and chain break load is further discussed in this chapter.

For the anchor chain, different steel qualities may be used within each equipment number. The required chain break loads for different steel qualities, listed in Table C.4, are based on information from DNV Rules for classification of ships /C-38/.

Table C.4 Chain break loads for different ship sizes /C-38/

Class	Anchor mass [kg]	Chain Break Load [kN]		
		NV K1	NV K2	NV K3
I	900	368	389	476
II	1440	581	655	735
III	3060	1220	1370	1540
IV	8700	3230	3610	3990
V	17800	5720	6510	7320
VI	26000	-	9030	10710

Except for anchor and chain characteristics, the anchor's holding power will depend on soil characteristics. Two different soils (sand and clay) have been chosen when estimating the holding power for stockless anchors of different size. In these estimations, the break load for the bitter end has not been used when deriving the limiting force from the anchor for conservative reasons. According to rules for classification for ships /C-38/, the strength of the bitter end should be between 15 % and 30 % of the chain break load. When the anchor is unintentionally dropped while in transport, it is likely but not certain that the full length of anchor chain will be paid out leaving the bitter end as the weak link. When the anchor chain pays out it could get stuck, or some other scenario could cause a part of the chain to remain in the locker. There are confirmed occasions where pipelines have suffered damage from dragged anchors from ships in transit and the anchor chain rather than the bitter end has broken due to stress.

From Table C.5 it can be concluded that the anchor holding power is less than both the anchor chain break load and the bitter end break load. Depending on the conditions related to soil, anchor size and chain strength, the difference in relation between anchor holding power and bitter end break load varies between 24 % and 80 % with the bitter end being the stronger part. When the anchor is dragged in the seabed at maximum penetration depth over longer distances, it is however likely that the anchor at some point will hit or get stuck into objects causing an instantaneous power in the chain significantly larger than the estimate for the anchors holding power. Therefore, it is reasonable to assume that the dragged anchor at maximum penetration depth in many cases will cause the bitter end to break. This is particularly likely for the smaller ships. For the larger ships (displacement ≥ 45000 tonnes), the likelihood for bitter end break is slightly less but on the other hand, the ships thrust in relation to the anchor's holding power is larger, meaning that it is more likely that the dragged anchor will be discovered by personnel on the bridge because of disturbances in the ship's manoeuvring ability. This requires the anchor to be well seated as dictated for outcome 2.

Table C.5 Overview of chain break load, bitter end break load and stockless anchor holding power for different ships and soil at maximum penetration depth

Class	Steel grade, break load [kN]			Average bitter end break load [kN]	Anchor holding power [kN], Hard Soil	Anchor holding power [kN], Soft Soil
	K1	K2	K3			
I	368	389	476	92	69	24
II	581	655	735	148	101	37
III	1220	1370	1540	310	185	74
IV	3230	3610	3990	812	426	194
V	5720	6510	7320	1466	756	375
VI	-	9030	10710	2221	1024	532

An overview of ships bollard thrust vs. ship size (in gross tonnage) is given in Figure C.6. For ship sizes up to 100 000 GRT, the diagram gives a good indication of how the two variables relate to each other.

For outcome 2 it can therefore be assumed that the result will be either i) chain/bitter end breakage or ii) notable impact on ship speed or manoeuvring ability meaning that the dragging distance in both cases is limited. The penetration depth may however be significant for this limited distance.

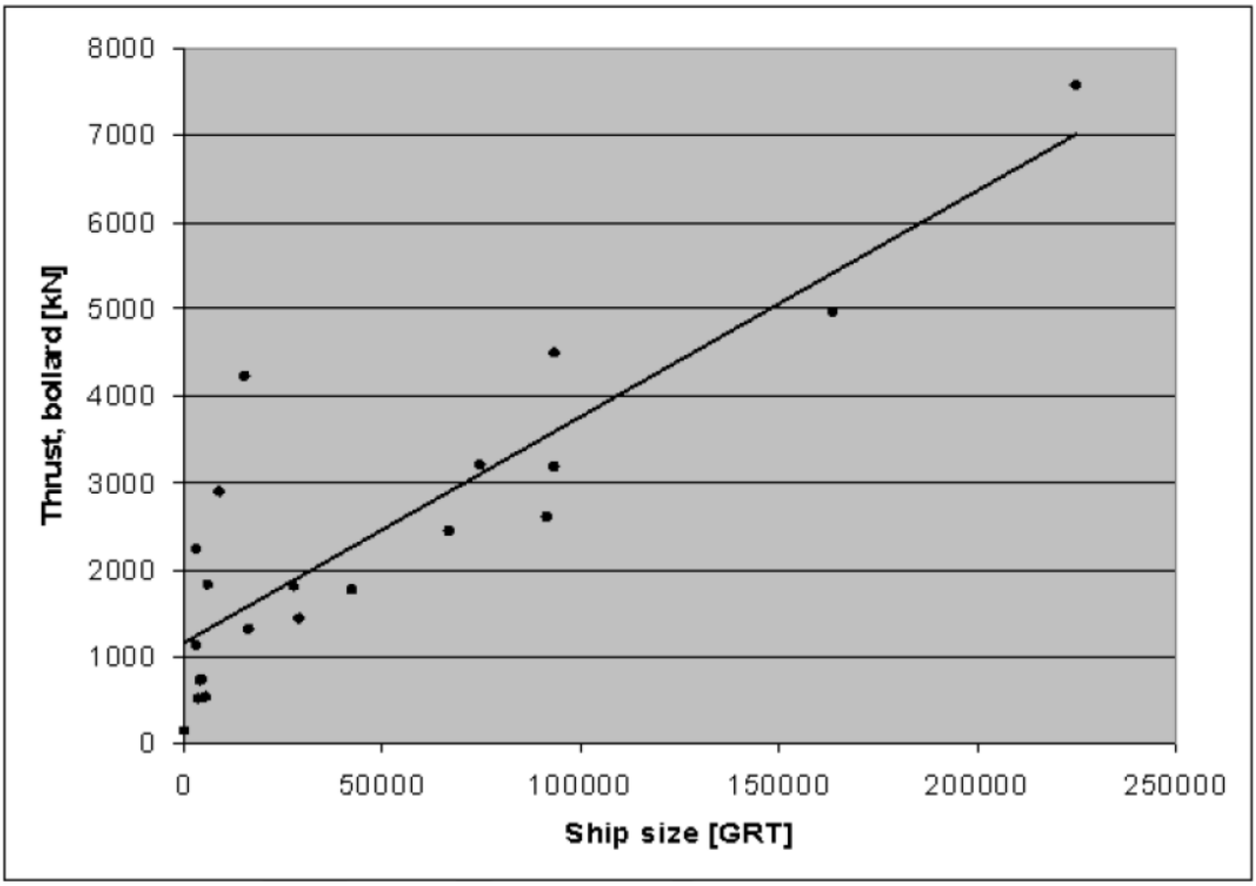


Figure C.6 Relation between ship size and thrust

C.4.5 Pipe load resistance

In this chapter two different causes to damage are treated. The first one is damage due to strain exceeding 5%. The other cause is dent exceeding 15% of the pipeline diameter caused by an anchor hooking and pulling the pipeline. Depending on what occurs first, either strain or dents will be the limiting factor. In this analysis, the pulling force rather than the actual impact of the anchor has been applied.

Damage due to strain:

- Pipeline diameter: 4”, 12”, 20”, 32”, 44”
- Pipeline protection method:
    - Fully embedded: Top of pipe directly under seabed (flush)

- o Trenched: Top of pipe 1 m beneath seabed
- o Exposed (not protected): Pipe located on top of seabed
- Soil condition: Soft, Hard

For parameters pressure and temperature, default values have been used. The pressure difference between pipe inside and outside is set to 100 bars. An increase in pressure will decrease the bend resistance of the pipe, meaning that 5 % strain will be reached earlier if the pressure is increased. The difference in bend resistance decreases with increasing strain limit, i.e. the difference in bend resistance at 5 % strain is larger (in relative terms) than at e.g. 10 % strain. The results from the analysis are presented in Table C.6.

Table C.6 Pipe load resistance - Strain

	Pipe	Anchor force at 5% strain [kN]		
		Exposed	Fully embedded	Trenched
Hard soil	4"	400	320	300
	12"	1880	1720	1200
	20"	2260	940	1580
	32"	2520	1340	2640
	44"	3700	2640	4600
Soft soil	4"	290	120	250
	12"	1920	440	810
	20"	2100	700	1260
	32"	2600	1360	2200
	44"	4200	2560	3600

From Table C.6, it can be concluded that exposed pipelines in many cases are less vulnerable when hooked by anchors than embedded or trenched ones. A pipe subject to high soil resistance will experience more local bending than a pipe that is not embedded and thus not subject to high soil resistance. The likelihood of being hooked by an anchor is however less for a trenched pipeline than for an exposed pipeline. The corresponding lateral displacement of the pipe is given in Table C.7.

Table C.7 Lateral displacement of pipe at 5% strain

	Pipe	Lateral displacement at 5% strain [m]		
		Exposed	Fully embedded	Trenched
Hard soil	4"	100	55	1.4
	12"	65	33	2.1
	20"	54	5.8	1.5
	32"	60	5.0	1.4
	44"	65	5.0	1.5
Soft soil	4"	98	5.5	-*)
	12"	73	4.1	2.1
	20"	62	2.6	1.6
	32"	60	2.6	1.6
	44"	61	3.2	2.1

* Within the accuracy of the model, no displacement is allowed (i.e. 5 % strain is reached before 1 m displacement)

Damage due to dent:

Based on /C-40/ the required force from a knife-edge rigid object perpendicular to the pipe wall to cause dents of varying size have been calculated and is showed in Figure C.7. A dent equal or larger than 10% of the pipeline diameter is considered damaged since this could cause a leak. The dent force and chain force required to cause 10 % relative dent depth for different pipeline diameters are presented in Table C.8.

An anchor hooking the pipeline will always have at least two (in general three) contact surfaces between the anchor and the pipe; one or two between the pipe and fluke(s) plus one between the shank and the pipe. Therefore, the force from the ship must be at least twice the force of the dent force from Figure C.7. The model resulting in the estimates presented in Figure C.7 assumes a knife edge shape striking the pipeline. In general, no parts of the anchor will actually be knife-edge shaped, making the estimate conservative.

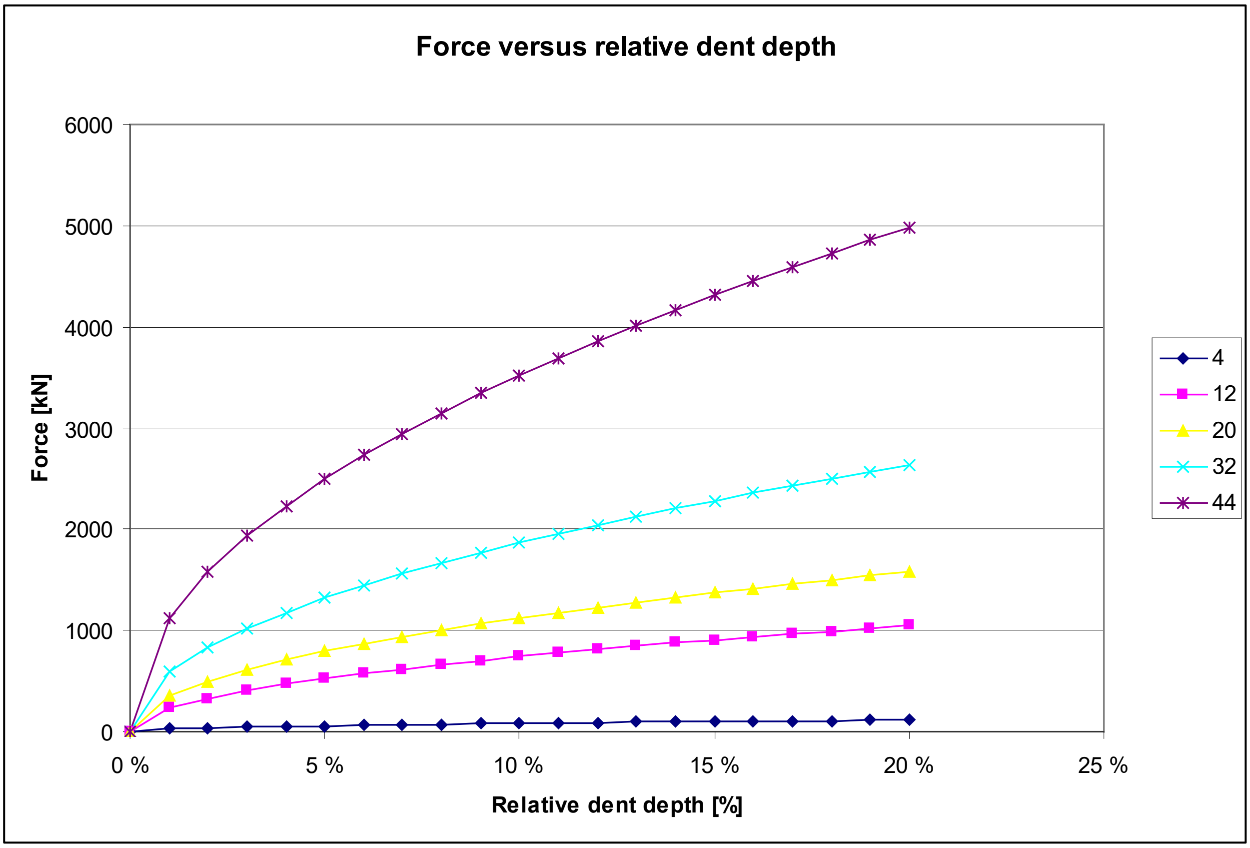


Figure C.7 Force versus relative dent depth for different pipeline diameters

Table C.8 Force causing 10 % relative dent depth for different pipeline diameters

Diameter	Dent force [kN]	Chain force [kN]
4”	82	164
12”	741	1482
20”	1120	2240
32”	1863	3726
44”	3522	7044

Strain versus dent:

Based on the results above, it is seen that strain is in general limiting the pipes load resistance and not dents. Table C.9 displays when strain or dents respectively constitute the limiting phenomena while Table C.10 displays the corresponding forces.

Table C.9 Limiting damage causes for different pipelines with

	Pipe	Limiting damage cause		
		Exposed	Fully embedded	Trenched
Hard soil	4"	Dent	Dent	Dent
	12"	Dent	Dent	Strain
	20"	Dent	Strain	Strain
	32"	Strain	Strain	Strain
	44"	Strain	Strain	Strain
Soft soil	4"	Dent	Strain	Dent
	12"	Dent	Strain	Strain
	20"	Strain	Strain	Strain
	32"	Strain	Strain	Strain
	44"	Strain	Strain	Strain

Table C.10 Limiting force from anchor causing either strain or dent according to criteria above

	Pipe	Limiting force from anchor		
		Exposed	Fully embedded	Trenched
Hard soil	4"	164	164	164
	12"	1482	1482	1200
	20"	2240	940	1580
	32"	2520	1340	2640
	44"	3700	2640	4600
Soft soil	4"	164	120	164
	12"	1482	440	810
	20"	2100	700	1260
	32"	2600	1360	2200
	44"	4200	2560	3600

C.5 Recorded lost anchors

To investigate the occurrence of lost anchors, information from DNV surveyor records has been used. In the period from 2017- 2024 the loss anchor loss rate observed varies from 0.8 – 1.3 % per calendar year, with an average of 1.1 %. This is a slight increase in loss rate compared with numbers reported in previous editions of this report, which in ref. /1/ was 1.0 %. The increase may however be caused by improved reporting routines. The loss rates reported for period covered does not indicate a specific trend.

The following overall explanation of when anchors are lost is given in ref. /C-36/:

- During normal anchoring in port anchorages.
    - When vessel has too much speed during anchoring.

- When dropped without control by the brake
- When dropping anchor in too deep water
- When dragging. (Sometimes this may also cause damage to cables and pipelines and cause collisions)

- When clutch disengages accidentally during anchoring operations
- When anchor is stuck or fouled
- When the hydraulic motor is engaged and the chain is pulled out by the vessel's movements
- Breakdown of windlass motor and the anchor and chain needs to be cut
- On voyage, if the chain is not properly secured
- In connection with emergency anchoring to avoid grounding & collisions

Anchor loss technical issues are reported as:

- Anchor loss due to failure of:
  - D-Shackle
  - Swivels
  - Chain
  - Kenter shackles

- Anchor and chain lost due to technical failure of:
  - Windlass motor
  - Windlass brakes
  - Chain stoppers

- Anchor loss operational issues are reported as
  - Use of brake
  - Heaving the anchor
  - Securing the anchor
  - Anchor watch
  - Lack of attention to bad weather

C.6 Frequency estimation

Based on the recorded lost anchors per ship and the alternative outcomes assessed above, a coarse estimate of the number of uncontrolled anchor drops per ship and year can be calculated. Subsequently, this can be used to estimate frequency for anchor - pipe interaction and pipe damage.

C.6.1 Accidental anchor drops per ship-year and per travelled distance [km]

It is concluded that the frequency for anchor loss is approximately 1.1E-02 per ship-year. The frequency of accidental anchor drops should however also consider the following two factors:

- Not all anchors dropped will be lost:
    - For outcome 1 it is assessed that all anchors will be retrieved, i.e. no anchors (0%) will be lost.
    - For outcome 2 it is assessed that half of the anchors will be retrieved, i.e. 50 % will be lost.
    - For outcome 3 it is assessed that all anchors (100 %) will be lost.
    - Combining with the probabilities for the outcomes, ref. Figure C.2, only 21,9 % of all anchors dropped will be lost.
    - The frequency of anchors dropped is thus 4.9E-02 per ship-year (i.e. equal to anchors lost per ship-year divided by 0.219)
- Not all anchors dropped are related to accidental anchor drops:
    - It is assumed that only 10% of the recorded lost anchors are related to accidental anchor drops.
    - The frequency of anchors accidentally dropped is thus 4.9E-03 per ship-year

The accidental anchor drop per travelled km can be calculated based on the average distance [km] travelled per ship-year. The fraction of time in transit, i.e. utilization, for ships varies depending on several factors such as type of ship, distance of normal route, and port time linked to type of goods.

- An average utilization of 70%, and an average speed of 15 knots (27.8 km/h), are assessed to be representative. This gives an average estimated travel distance of 1.7E-05 km per ship-year.
- By dividing the frequency of anchors accidentally dropped per ship-year, by the distance travelled per ship-year, results in an accidental anchor drop per travelled km of 2.9E-08.

C.6.2 Anchor - Pipe interaction

The three different outcomes all result in a situation where an anchor is dragged over a certain distance and may interact with a pipeline. An interaction in this case is defined as a scenario where the anchor gets in contact with the pipeline *or* is dragged above the trenched pipeline. I.e. interaction is not limited to damage or hooking of the pipeline. The scenario where the anchor chain is too short to enable the anchor to reach the seabed is not included here.

The frequency for anchor - pipe interaction is calculated for each outcome, based on the probability of the anchor being dropped within a timeframe prior to the pipeline passing. The timeframe from anchor is dropped, until an interaction with a pipeline cannot exceed the timeframe for which it is calculated that the dropped anchor is dragged until either; the crew becomes aware of the anchor being dropped, or the anchor hooks onto something and is lost.

Outcome 1

The first outcome describes the situation where the anchor is dropped uncontrolled but discovered within 1 km without having reached its maximum penetration depth. Unless the anchor impacts a pipeline within the 1 km dragging distance after being dropped, the dropped anchor is assessed to be discovered and retrieved after being dragged 1 km.

- Outcome 1 is assigned a 75% probability. Combined with the total probability of anchor drops per ship-year the probability of anchor drops per ship-year associated with this outcome will thus be 3.7E-03.
- For the anchor to interact with a pipeline it must, for this outcome, be dropped within the last 1 km distance travelled before intersecting the pipeline. The probability of the anchor being dropped within a distance of 1 km is calculated based on the frequency of the outcome per ship-year, multiplied by this distance (i.e. 1 km), and divided by the average total distance travelled per ship-year (1.7E-05 km), which is 2.2E-08.

For this outcome it is assumed that the anchor does not get seated but is discovered through noise and vibrations etc. when being paid out. Penetration depth is therefore limited to one fluke length and anchors are assumed to be recovered and not lost.

Outcome 2

The second outcome describes the situation where the anchor is seated into the seabed within 1 km. Unless the anchor impacts a pipeline within the 1 km dragging distance after being dropped, it is in this case assessed that either the anchor is lost after being dragged 1 km, or the crew becomes aware of the dropped anchor and stop the vessel to retrieve it after travelling 1 km.

- Outcome 2 was assigned a 1/16 probability (0.25 x 0.25). Combined with the total probability of anchor drops per ship-year the probability of anchor drops per ship-year associated with this outcome will thus be 3.1E-04.
- For the anchor to interact with a pipeline it must, for this outcome, be dropped within the last 1 km distance travelled before intersecting the pipeline. The probability of the anchor being dropped within a distance of 1 km is calculated based on the frequency of the outcome per ship-year, multiplied by this distance (i.e. 1 km), and divided by the average total distance travelled per ship-year (1.7E-05 km), which is 1.8E-09.

Outcome 3

The third outcome is more complex when it comes to distance travelled for which an anchor may be dropped, in order to interact with a pipeline. For outcome 1 and 2, the distance was simply assumed to be 1 km, while for this outcome, the dragged and unseated anchor could be assumed to be dragged from any point where it is dropped and all the way until hooking to a pipeline or any other possible obstruction on the seabed.

The distance over which an anchor may be dropped and dragged before interacting with a specific pipeline will thus be the distance from the previous obstruction where it would have been hooked, to this specific pipeline. Establishing this distance is very difficult, even for one specific pipeline. And it is likely to vary significantly also between pipelines. Some factors assessed to affect the distance from the previous obstruction where a dragged anchor will be hooked, and the point on a pipeline intersected by a vessel possibly dragging an anchor, are listed below:

- Even if the anchor is dragged over another obstruction before the vessel intersect the pipeline, there will always be a certain probability for a previous obstruction not to hook the anchor. In this case the distance over which an anchor may be dropped and dragged before intersecting a pipeline may extend farther than the distance between the previous obstruction and this specific pipeline.
- The distance from a previous obstruction to the point on a specific pipeline where a vessel may intersect will vary significantly along the route of this specific pipeline.
- The distance from a previous obstruction to the point on a specific pipeline where a vessel may intersect will vary significantly depending on the direction the vessel is approaching from.

- For a pipeline point close to a high sea-depth gradient, and if the vessel is approaching from the deeper part of the sea, any previous obstacles may, depending on the chain length, be too deep to interact with the anchor being dragged.
- A pipeline, or specific point on a pipeline, which is relatively close to other pipelines (or obstructions in general) may be assessed less exposed, since the anchor is more likely to be hooked at the first pipeline or obstruction it is intersecting. And vice versa for a pipeline which is located far away from other pipelines.

Based on the above listed factors it is evident that the distance for which an anchor may be dropped and dragged, before interacting with a specific pipeline, will vary significantly over the length of this pipeline. And also, that there will be significant variations between different pipelines.

It can be argued that despite a significant variation along the length of any specific pipeline, the average value (per pipeline distance) for different pipeline in the same area may vary less. Some variation between pipelines should however be expected. Nevertheless, for practical reasons, a representative distance over which an anchor may be dropped and dragged, before intersecting a pipeline, has been established as follows:

- In areas where the seabed mainly consists of different kinds of clay or sand, it could be assumed that obstructions with potential to hook an anchor will mainly consist of artificial objects such as pipelines and cables. For simplicity the cables have been disregarded when calculating average distance to the first obstructions on the seabed.
- An average distance between obstructions, if only considering pipelines, may be calculated based on a total pipeline distance over an area. The total amount of offshore pipelines, measured in distance [km], included in this study is approximately 27 000 km. Some of these pipelines are stretching beyond the North Sea to the nearby Norwegian Sea and Skagerrak. The majority (80 – 90%) of the total pipeline distance is however expected to be within the 750 000 km^2 North Sea area.
- The vessel and anchor may approach the pipeline with an angle between 0 and 90 degrees. For simplicity the anchor hooking the pipeline is in this model assumed to strike the pipeline perpendicular to the stretch of the pipeline. When assuming a perpendicular strike the force will be conservative. However, imagining all pipelines in the area is aligned in parallel, the shortest mean distance between pipelines will be for a vessel travelling perpendicular to the pipelines.
- Assuming perpendicular anchor approach, and that pipelines are evenly spread out (in parallel to each other) in the North Sea, gives and average distance between the pipelines of 33 km. The average distance travelled over which an anchor may be dropped and dragged before interacting with a specific pipeline is thus calculated to 33 km.

Based on the above assessments the probability for an anchor interacting with a pipeline is calculated:

- Outcome 3 was assigned a 3/16 probability (0.25 x 0.75). Combined with the total probability of anchor drops per ship-year the probability of anchor drops per ship-year associated with this outcome will thus be 9.2E-04.
- For the anchor to interact with a pipeline it is for this outcome assessed that the anchor must be dropped within the last 33 km distance travelled before intersecting the pipeline. The probability of the anchor being dropped within a distance of 33 km is calculated based on the frequency of the outcome per ship-year, multiplied by this distance (i.e. 33 km), and divided by the average total distance travelled per ship-year (1.7E-05 km), which is 1.8E-07.

The probability calculated for an interaction between dragged anchor and pipeline, per vessel crossing the pipeline, is as described above assessed to be representative for pipelines located in the North Sea. It should however be acknowledged that the probability will not only depend on a vessel crossing, but also depend on where along the pipeline the vessel is crossing, i.e. how close this point of crossing is to other obstructions with potential to hook the anchor.

If the pipeline is located in an area outside the North Sea, it may be justified to adjust the frequency (i.e. by adjusting the representative distance for which an anchor may be dropped and dragged before interacting with the pipeline), if it can be documented that the density of other obstructions, e.g. nearby pipelines or other obstructions, deviates significantly from the North Sea.

- In an area with significantly lower density of obstructions, the potential distance travelled over which the anchor may be dropped and dragged, and thus the interaction frequency, should be increased.
- Similarly, in an area with significantly higher density of obstructions, the potential distance travelled over which the anchor may be dropped and dragged, and thus the interaction frequency, should be reduced.
- It must be noted that several factors affecting the interaction frequency are not considered in the simplified methodology described above. To adjust the distance over which an anchor may be dropped and dragged before interacting with a specific pipeline, only based on the presence of other pipelines in the area is thus not recommended. It is recommended to keep the adjusted value for outcome 3 within a factor two, i.e. no less than 9E-08 for an area assessed to have a high density of obstructions, and no more than 3.6E-07 in an area assessed to have a low density of obstructions.

C.6.3 Hooking and damage to pipeline

Whether the pipeline could be hooked and subsequently damaged by a dragged anchor or not, depends on various factors as described above. An analysis including five different pipeline diameters have provided a set of estimated damage frequencies. The diameters chosen in the analysis were 4", 12", 20", 32" and 44". In annex 1, a table of sequency criteria for each of the outcomes 1, 2 and 3 is presented with branches for pipeline diameter, protection, soil and ship displacement.

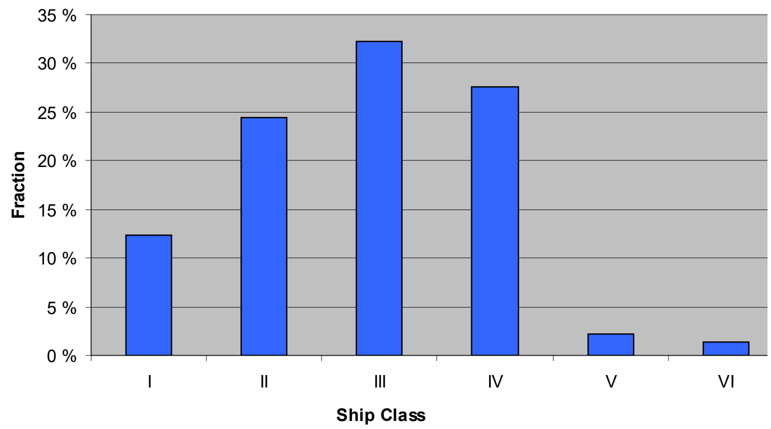
If the number of crossings per time unit and distribution of ship size are known, the frequencies in outcome 1, 2 and 3 can be combined with this data to form the aggregated frequency of damage to pipelines due to uncontrolled anchor drops. The complete table for such an analysis is given in Annex II.

When the ship size distribution is unknown, a default distribution may be applied. Based on collected data from five different shipping lanes in the North Sea (/C-41/, /C-42/) the distribution in Figure C.8 may be applied as a default distribution to reflect a typical lane with ship traffic in the North Sea. The result from applying the default distribution is given in Table C.11. The table assumes that the water depth is such that the anchor chain is long enough to allow the anchor to reach the seabed. In those cases where the anchor chain for a ship class is too short, that frequency contribution should not be included in the estimates for final failure frequency.

C.6.4 Hole size distribution

It is suggested to conservatively assume all incidents exceeding the damage criteria will lead to pipeline failure, i.e. loss of containment. It is reasonable to expect that for some incidents the failure will occur immediately, while in other cases the damage will lead to rapid failure development, however not immediate failure.

There is not sufficient data available to support a specific distribution in immediate and delayed failure, nor to suggest a specific hole size distribution for failures caused by dragged anchor. Due to lack of such input it is recommended to model the consequence as similar to other pipeline failures, i.e. as an immediate failure and with the generic hole size distribution as specified for the relevant pipeline type.



Ship Class	Proportion
I	12 %
II	24 %
III	33 %
IV	28 %
V	2 %
VI	1 %

Figure C.8 Default distribution of ship size in the North Sea

Table C.11 Estimated damage frequencies per ship crossing for pipelines based on a default ship size distribution

Pipe Diameter	Protection method	Soil	F_{damage} per ship crossing assuming a fixed class distribution
4"	Exposed	Soft	2.0E-07
		Hard	2.0E-07
	Flush	Soft	2.0E-07
		Hard	2.0E-07
	Trenched	Soft	6.3E-08
		Hard	6.2E-08
12"	Exposed	Soft	6.2E-08
		Hard	6.2E-08
	Flush	Soft	2.0E-07
		Hard	6.2E-08
	Trenched	Soft	6.2E-08
		Hard	6.2E-08
20"	Exposed	Soft	6.0E-09
		Hard	6.0E-09
	Flush	Soft	1.8E-07
		Hard	1.3E-07
	Trenched	Soft	6.2E-08
		Hard	6.2E-08
32"	Exposed	Soft	6.0E-09
		Hard	6.0E-09
	Flush	Soft	6.2E-08
		Hard	6.2E-08
	Trenched	Soft	6.0E-09
		Hard	6.0E-09
44"	Exposed	Soft	2.0E-09
		Hard	2.0E-09
	Flush	Soft	6.0E-09
		Hard	6.0E-09
	Trenched	Soft	2.0E-09
		Hard	2.0E-09

C.6.4 Example cases

The chapter contains two example cases of how to estimate the damage frequency (per year) due to uncontrolled anchor drops for a pipeline in the North Sea. Example 1 is applicable when the number of ship crossings and distribution of size is known. Example 2 is applicable when only the number of ship crossings is known but not the distribution of ship size. The standard distribution of ship size in Figure C.8 is applied in the second example.

Example 1

Estimate annual damage frequency to the pipeline due to uncontrolled anchor drops based on the following input given:

- Pipeline diameter: 20”
- Protection philosophy: Exposed
- Soil: Sand (Hard)
- Water depth: 100 m
- Annual number of ship crossings
    - Ship class I: 100
    - Ship class II: 100
    - Ship class III: 150
    - Ship class IV: 150
    - Ship class V: 20
    - Ship class VI: 2

Solution:

- Based on information regarding anchor chain length given in Table C.1, all ship classes will have an anchor chain length sufficient to reach down to the seabed.
- Based on the projected fluke length given in Table C.2 (minimum 23.6”), the fluke length of anchors from all ship classes exceed half the diameter of all pipeline classes included in the analysis (maximum 44”).
- For ship classes I, II and III, the chain strength given in Table C.4 (column NV K3), does not exceed the pipeline load resistance for a 20” inch exposed pipeline on hard soil given in Table C.6. For the remaining ship classes, the chain strength exceeds the pipeline load resistance, and damage is possible.
- For ship classes I, II, III and IV, the thrust force calculated, using the relationship between thrust force and vessel gross tonnage given in Figure C.6, does not exceed the pipeline load resistance for a 20” inch exposed pipeline on hard soil given in Table C.6. For the remaining ship classes, the thrust force exceeds the pipeline load resistance, and damage is possible.

Thus, only anchors dragged by vessels in ship classes V and VI will cause pipeline damage. Combining this with the damage frequency per ship crossing given in Annex I, and number of ships within each ship class passing the pipeline the total frequency can be calculated as presented in Table C.12.

Table C.12 Annual damage frequency calculation for example case 1

Ship class	Sufficiently long anchor chain	Sufficiently large anchor fluke	Chain strength exceeding resistance	Thrust force exceeding resistance	Damage frequency per ship crossing and ship class	Number of crossings per year	Damage frequency per ship class and year
I	Yes	Yes	No	No	Negl.	100	Negl.
II	Yes	Yes	No	No	Negl.	100	Negl.
III	Yes	Yes	No	No	Negl.	150	Negl.
IV	Yes	Yes	Yes	No	Negl.	150	Negl.
V	Yes	Yes	Yes	Yes	2.0E-07	20	4.0E-6
VI	Yes	Yes	Yes	Yes	2.0E-07	2	4.0E-7
						Total:	**4.4E-6**

Example 2

Estimate annual damage frequency to the pipeline due to uncontrolled anchor drops based on the following input given:

- Pipeline diameter: 32”
- Protection philosophy: Exposed
- Soil: Clay (Soft)
- Water depth: 100 m
- Annual number of ship crossings: 400

Solution:

- Based on information regarding anchor chain length given in Table C.1, all ship classes will have an anchor chain length sufficient to reach down to the seabed.
- Based on the projected fluke length given in Table C.2 (minimum 23.6”), the fluke length of anchors from all ship classes exceed half the diameter of all pipeline classes included in the analysis (maximum 44”).
- For ship classes I, II and III, the chain strength given in Table C.4 (column NV K3), does not exceed the pipeline load resistance for a 32” inch exposed pipeline on soft soil given in Table C.6. For the remaining ship classes, the chain strength exceeds the pipeline load resistance, and damage is possible.
- For ship classes I, II, III and IV, the thrust force calculated, using the relationship between thrust force and vessel gross tonnage given in Figure C.6, does not exceed the pipeline load resistance for a 32” inch exposed pipeline on soft soil given in Table C.6. For the remaining ship classes, the thrust force exceeds the pipeline load resistance, and damage is possible.

Thus, only anchors dragged by vessels in ship classes V and VI will cause pipeline damage. Combining this with the damage frequency per ship crossing given in Annex I, the ship class distribution given in Figure C.8, and total number of ships passing the pipeline the total frequency can be calculated as presented in Table C.13.

Table C.13 Annual damage frequency calculation for example case 2

Ship class	Sufficiently long anchor chain	Sufficiently large anchor fluke	Chain strength exceeding resistance	Thrust force exceeding resistance	Damage frequency per ship crossing and ship class	Ship class distribution	Damage frequency per ship class and year
I	Yes	Yes	No	No	Negl.	12 %	Negl.
II	Yes	Yes	No	No	Negl.	24 %	Negl.
III	Yes	Yes	No	No	Negl.	33 %	Negl.
IV	Yes	Yes	Yes	No	Negl.	28 %	Negl.
V	Yes	Yes	Yes	Yes	2.0E-07	2 %	4.0E-9
VI	Yes	Yes	Yes	Yes	2.0E-07	1 %	2.0E-9
						Total per ship passing:	6.0E-9
						Total for 400 ship passings:	**2.4E-6**

C.7 References

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/C-39/ DNV, *Rules for Classification, Ships*, Part 3 – Hull, Chapter 11, July 2024.

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/C-42/ Statoil, *Europipe 2 - Risk from external interference*, D052-XX-P100-F-RS-020, Rev 3 2004.

/C-43/ Statoil, *Zeepipe Development Project*, DO24-A-P50-F-RS-005-01, Rev 6 1990

/C-44/ Gaudin C., Vlahos G., Randoloph M.F., *Centrifuge Tests to Design Pipeline Rock Protection – Report no. C: 2090*, Centre for Offshore Foundation Systems, The University of Western Australia 2006

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ANNEX 1

CRITERIA FOR DAMAGE TO PIPELINES

Diameter [inches]	Protection	Soil	Ship displacement [tones]	(All three outcomes) Projected fluke length > pipeline diameter / 2	(Outcome 1 and 3) Anchor depth exceed pipeline depth and half diameter	(Outcome 2) Anchor depth exceed pipeline depth and half diameter	(All three outcomes) Chain strength > Load resistance	(All three outcomes) Thrust + Force from kinetic energy > Load resistance	(Outcome 1 and 3) Damage	(Outcome 2) Damage
4	Exposed	Soft	1500	Yes	Yes	Yes	Yes	Yes	Yes	Yes
			3600	Yes	Yes	Yes	Yes	Yes	Yes	Yes
			10000	Yes	Yes	Yes	Yes	Yes	Yes	Yes
			45000	Yes	Yes	Yes	Yes	Yes	Yes	Yes
			175000	Yes	Yes	Yes	Yes	Yes	Yes	Yes
			350000	Yes	Yes	Yes	Yes	Yes	Yes	Yes
		Hard	1500	Yes	Yes	Yes	Yes	Yes	Yes	Yes
			3600	Yes	Yes	Yes	Yes	Yes	Yes	Yes
			10000	Yes	Yes	Yes	Yes	Yes	Yes	Yes
			45000	Yes	Yes	Yes	Yes	Yes	Yes	Yes
			175000	Yes	Yes	Yes	Yes	Yes	Yes	Yes
			350000	Yes	Yes	Yes	Yes	Yes	Yes	Yes
	Flush	Soft	1500	Yes	Yes	Yes	Yes	Yes	Yes	Yes
			3600	Yes	Yes	Yes	Yes	Yes	Yes	Yes
			10000	Yes	Yes	Yes	Yes	Yes	Yes	Yes
			45000	Yes	Yes	Yes	Yes	Yes	Yes	Yes
			175000	Yes	Yes	Yes	Yes	Yes	Yes	Yes
			350000	Yes	Yes	Yes	Yes	Yes	Yes	Yes
		Hard	1500	Yes	Yes	Yes	Yes	Yes	Yes	Yes
			3600	Yes	Yes	Yes	Yes	Yes	Yes	Yes
			10000	Yes	Yes	Yes	Yes	Yes	Yes	Yes
			45000	Yes	Yes	Yes	Yes	Yes	Yes	Yes
			175000	Yes	Yes	Yes	Yes	Yes	Yes	Yes
			350000	Yes	Yes	Yes	Yes	Yes	Yes	Yes
	Trenched	Soft	1500	Yes	No	Yes	Yes	Yes	No	Yes
			3600	Yes	No	Yes	Yes	Yes	No	Yes
			10000	Yes	No	Yes	Yes	Yes	No	Yes
			45000	Yes	Yes	Yes	Yes	Yes	Yes	Yes
			175000	Yes	Yes	Yes	Yes	Yes	Yes	Yes
			350000	Yes	Yes	Yes	Yes	Yes	Yes	Yes
		Hard	1500	Yes	No	No	Yes	Yes	No	No
			3600	Yes	No	No	Yes	Yes	No	No
			10000	Yes	No	No	Yes	Yes	No	No
			45000	Yes	Yes	Yes	Yes	Yes	Yes	Yes
			175000	Yes	Yes	Yes	Yes	Yes	Yes	Yes
			350000	Yes	Yes	Yes	Yes	Yes	Yes	Yes

Diameter [inches]	Protection	Soil	Ship displacement [tones]	(All three outcomes) Projected fluke length > pipeline diameter / 2	(Outcome 1 and 3) Anchor depth exceed pipeline depth and half diameter	(Outcome 2) Anchor depth exceed pipeline depth and half diameter	(All three outcomes) Chain strength > Load resistance	(All three outcomes) Thrust + Force from kinetic energy > Load resistance	(Outcome 1 and 3) Damage	(Outcome 2) Damage
12	Exposed	Soft	1500	Yes	Yes	Yes	No	No	No	No
			3600	Yes	Yes	Yes	No	No	No	No
			10000	Yes	Yes	Yes	Yes	No	No	No
			45000	Yes	Yes	Yes	Yes	Yes	Yes	Yes
			175000	Yes	Yes	Yes	Yes	Yes	Yes	Yes
			350000	Yes	Yes	Yes	Yes	Yes	Yes	Yes
		Hard	1500	Yes	Yes	Yes	No	No	No	No
			3600	Yes	Yes	Yes	No	No	No	No
			10000	Yes	Yes	Yes	Yes	No	No	No
			45000	Yes	Yes	Yes	Yes	Yes	Yes	Yes
			175000	Yes	Yes	Yes	Yes	Yes	Yes	Yes
			350000	Yes	Yes	Yes	Yes	Yes	Yes	Yes
	Flush	Soft	1500	Yes	Yes	Yes	Yes	Yes	Yes	Yes
			3600	Yes	Yes	Yes	Yes	Yes	Yes	Yes
			10000	Yes	Yes	Yes	Yes	Yes	Yes	Yes
			45000	Yes	Yes	Yes	Yes	Yes	Yes	Yes
			175000	Yes	Yes	Yes	Yes	Yes	Yes	Yes
			350000	Yes	Yes	Yes	Yes	Yes	Yes	Yes
		Hard	1500	Yes	Yes	Yes	No	No	No	No
			3600	Yes	Yes	Yes	No	No	No	No
			10000	Yes	Yes	Yes	Yes	No	No	No
			45000	Yes	Yes	Yes	Yes	Yes	Yes	Yes
			175000	Yes	Yes	Yes	Yes	Yes	Yes	Yes
			350000	Yes	Yes	Yes	Yes	Yes	Yes	Yes
	Trenched	Soft	1500	Yes	No	Yes	No	Yes	No	No
			3600	Yes	No	Yes	No	Yes	No	No
			10000	Yes	No	Yes	Yes	Yes	No	Yes
			45000	Yes	Yes	Yes	Yes	Yes	Yes	Yes
			175000	Yes	Yes	Yes	Yes	Yes	Yes	Yes
			350000	Yes	Yes	Yes	Yes	Yes	Yes	Yes
		Hard	1500	Yes	No	No	No	No	No	No
			3600	Yes	No	No	No	No	No	No
			10000	Yes	No	No	Yes	Yes	No	No
			45000	Yes	Yes	Yes	Yes	Yes	Yes	Yes
			175000	Yes	Yes	Yes	Yes	Yes	Yes	Yes
			350000	Yes	Yes	Yes	Yes	Yes	Yes	Yes

Diameter [inches]	Protection	Soil	Ship displacement [tones]	(All three outcomes) Projected fluke length > pipeline diameter / 2	(Outcome 1 and 3) Anchor depth exceed pipeline depth and half diameter	(Outcome 2) Anchor depth exceed pipeline depth and half diameter	(All three outcomes) Chain strength > Load resistance	(All three outcomes) Thrust + Force from kinetic energy > Load resistance	(Outcome 1 and 3) Damage	(Outcome 2) Damage
20	Exposed	Soft	1500	Yes	Yes	Yes	No	No	No	No
			3600	Yes	Yes	Yes	No	No	No	No
			10000	Yes	Yes	Yes	No	No	No	No
			45000	Yes	Yes	Yes	Yes	No	No	No
			175000	Yes	Yes	Yes	Yes	Yes	Yes	Yes
			350000	Yes	Yes	Yes	Yes	Yes	Yes	Yes
		Hard	1500	Yes	Yes	Yes	No	No	No	No
			3600	Yes	Yes	Yes	No	No	No	No
			10000	Yes	Yes	Yes	No	No	No	No
			45000	Yes	Yes	Yes	Yes	No	No	No
			175000	Yes	Yes	Yes	Yes	Yes	Yes	Yes
			350000	Yes	Yes	Yes	Yes	Yes	Yes	Yes
	Flush	Soft	1500	Yes	Yes	Yes	No	Yes	No	No
			3600	Yes	Yes	Yes	Yes	Yes	Yes	Yes
			10000	Yes	Yes	Yes	Yes	Yes	Yes	Yes
			45000	Yes	Yes	Yes	Yes	Yes	Yes	Yes
			175000	Yes	Yes	Yes	Yes	Yes	Yes	Yes
			350000	Yes	Yes	Yes	Yes	Yes	Yes	Yes
		Hard	1500	Yes	Yes	Yes	No	Yes	No	No
			3600	Yes	Yes	Yes	No	Yes	No	No
			10000	Yes	Yes	Yes	Yes	Yes	Yes	Yes
			45000	Yes	Yes	Yes	Yes	Yes	Yes	Yes
			175000	Yes	Yes	Yes	Yes	Yes	Yes	Yes
			350000	Yes	Yes	Yes	Yes	Yes	Yes	Yes
	Trenched	Soft	1500	Yes	No	Yes	No	No	No	No
			3600	Yes	No	Yes	No	No	No	No
			10000	Yes	No	Yes	Yes	Yes	No	Yes
			45000	Yes	Yes	Yes	Yes	Yes	Yes	Yes
			175000	Yes	Yes	Yes	Yes	Yes	Yes	Yes
			350000	Yes	Yes	Yes	Yes	Yes	Yes	Yes
		Hard	1500	Yes	No	No	No	No	No	No
			3600	Yes	No	No	No	No	No	No
			10000	Yes	No	No	No	No	No	No
			45000	Yes	Yes	Yes	Yes	Yes	Yes	Yes
			175000	Yes	Yes	Yes	Yes	Yes	Yes	Yes
			350000	Yes	Yes	Yes	Yes	Yes	Yes	Yes

Diameter [inches]	Protection	Soil	Ship displacement [tones]	(All three outcomes) Projected fluke length > pipeline diameter / 2	(Outcome 1 and 3) Anchor depth exceed pipeline depth and half diameter	(Outcome 2) Anchor depth exceed pipeline depth and half diameter	(All three outcomes) Chain strength > Load resistance	(All three outcomes) Thrust + Force from kinetic energy > Load resistance	(Outcome 1 and 3) Damage	(Outcome 2) Damage
32	Exposed	Soft	1500	Yes	Yes	Yes	No	No	No	No
			3600	Yes	Yes	Yes	No	No	No	No
			10000	Yes	Yes	Yes	No	No	No	No
			45000	Yes	Yes	Yes	Yes	No	No	No
			175000	Yes	Yes	Yes	Yes	Yes	Yes	Yes
			350000	Yes	Yes	Yes	Yes	Yes	Yes	Yes
		Hard	1500	Yes	Yes	Yes	No	No	No	No
			3600	Yes	Yes	Yes	No	No	No	No
			10000	Yes	Yes	Yes	No	No	No	No
			45000	Yes	Yes	Yes	Yes	No	No	No
			175000	Yes	Yes	Yes	Yes	Yes	Yes	Yes
			350000	Yes	Yes	Yes	Yes	Yes	Yes	Yes
	Flush	Soft	1500	Yes	Yes	Yes	No	No	No	No
			3600	Yes	Yes	Yes	No	No	No	No
			10000	Yes	Yes	Yes	Yes	No	No	No
			45000	Yes	Yes	Yes	Yes	Yes	Yes	Yes
			175000	Yes	Yes	Yes	Yes	Yes	Yes	Yes
			350000	Yes	Yes	Yes	Yes	Yes	Yes	Yes
		Hard	1500	Yes	Yes	Yes	No	No	No	No
			3600	Yes	Yes	Yes	No	No	No	No
			10000	Yes	Yes	Yes	Yes	No	No	No
			45000	Yes	Yes	Yes	Yes	Yes	Yes	Yes
			175000	Yes	Yes	Yes	Yes	Yes	Yes	Yes
			350000	Yes	Yes	Yes	Yes	Yes	Yes	Yes
	Trenched	Soft	1500	Yes	No	Yes	No	No	No	No
			3600	Yes	No	Yes	No	No	No	No
			10000	Yes	No	Yes	No	No	No	No
			45000	Yes	No	Yes	Yes	No	No	No
			175000	Yes	Yes	Yes	Yes	Yes	Yes	Yes
			350000	Yes	Yes	Yes	Yes	Yes	Yes	Yes
		Hard	1500	Yes	No	No	No	No	No	No
			3600	Yes	No	No	No	No	No	No
			10000	Yes	No	No	No	No	No	No
			45000	Yes	No	No	Yes	No	No	No
			175000	Yes	Yes	Yes	Yes	Yes	Yes	Yes
			350000	Yes	Yes	Yes	Yes	Yes	Yes	Yes

Diameter [inches]	Protection	Soil	Ship displacement [tones]	(All three outcomes) Projected fluke length > pipeline diameter / 2	(Outcome 1 and 3) Anchor depth exceed pipeline depth and half diameter	(Outcome 2) Anchor depth exceed pipeline depth and half diameter	(All three outcomes) Chain strength > Load resistance	(All three outcomes) Thrust + Force from kinetic energy > Load resistance	(Outcome 1 and 3) Damage	(Outcome 2) Damage
44	Exposed	Soft	1500	Yes	Yes	Yes	No	No	No	No
			3600	Yes	Yes	Yes	No	No	No	No
			10000	Yes	Yes	Yes	No	No	No	No
			45000	Yes	Yes	Yes	No	No	No	No
			175000	Yes	Yes	Yes	Yes	No	No	No
			350000	Yes	Yes	Yes	Yes	Yes	Yes	Yes
		Hard	1500	Yes	Yes	Yes	No	No	No	No
			3600	Yes	Yes	Yes	No	No	No	No
			10000	Yes	Yes	Yes	No	No	No	No
			45000	Yes	Yes	Yes	Yes	No	No	No
			175000	Yes	Yes	Yes	Yes	No	No	No
			350000	Yes	Yes	Yes	Yes	Yes	Yes	Yes
	Flush	Soft	1500	Yes	Yes	Yes	No	No	No	No
			3600	Yes	Yes	Yes	No	No	No	No
			10000	Yes	Yes	Yes	No	No	No	No
			45000	Yes	Yes	Yes	Yes	No	No	No
			175000	Yes	Yes	Yes	Yes	Yes	Yes	Yes
			350000	Yes	Yes	Yes	Yes	Yes	Yes	Yes
		Hard	1500	Yes	Yes	Yes	No	No	No	No
			3600	Yes	Yes	Yes	No	No	No	No
			10000	Yes	Yes	Yes	No	No	No	No
			45000	Yes	Yes	Yes	Yes	No	No	No
			175000	Yes	Yes	Yes	Yes	Yes	Yes	Yes
			350000	Yes	Yes	Yes	Yes	Yes	Yes	Yes
	Trenched	Soft	1500	Yes	No	Yes	No	No	No	No
			3600	Yes	No	Yes	No	No	No	No
			10000	Yes	No	Yes	No	No	No	No
			45000	Yes	No	Yes	Yes	No	No	No
			175000	Yes	Yes	Yes	Yes	No	No	No
			350000	Yes	Yes	Yes	Yes	Yes	Yes	Yes
		Hard	1500	Yes	No	No	No	No	No	No
			3600	Yes	No	No	No	No	No	No
			10000	Yes	No	No	No	No	No	No
			45000	Yes	No	No	No	No	No	No
			175000	Yes	Yes	Yes	Yes	No	No	No
			350000	Yes	Yes	Yes	Yes	Yes	Yes	Yes

ANNEX 2

DAMAGE FREQUENCIES FOR PIPELINES PER SHIP CROSSING AND SHIP SIZE

Protection	Soil	Ship displacement [tones]	f_{damage} [per ship crossing], for each pipeline diameter category				
			4”	12”	20”	32”	44”
Exposed	Soft	1500	2.0E-07	-	-	-	-
		3600	2.0E-07	-	-	-	-
		10000	2.0E-07	-	-	-	-
		45000	2.0E-07	2.0E-07	-	-	-
		175000	2.0E-07	2.0E-07	2.0E-07	2.0E-07	-
		350000	2.0E-07	2.0E-07	2.0E-07	2.0E-07	2.0E-07
	Hard	1500	2.0E-07	-	-	-	-
		3600	2.0E-07	-	-	-	-
		10000	2.0E-07	-	-	-	-
		45000	2.0E-07	2.0E-07	-	-	-
		175000	2.0E-07	2.0E-07	2.0E-07	2.0E-07	-
		350000	2.0E-07	2.0E-07	2.0E-07	2.0E-07	2.0E-07
Flush	Soft	1500	2.0E-07	2.0E-07	-	-	-
		3600	2.0E-07	2.0E-07	2.0E-07	-	-
		10000	2.0E-07	2.0E-07	2.0E-07	-	-
		45000	2.0E-07	2.0E-07	2.0E-07	2.0E-07	-
		175000	2.0E-07	2.0E-07	2.0E-07	2.0E-07	2.0E-07
		350000	2.0E-07	2.0E-07	2.0E-07	2.0E-07	2.0E-07
	Hard	1500	2.0E-07	-	-	-	-
		3600	2.0E-07	-	-	-	-
		10000	2.0E-07	-	2.0E-07	-	-
		45000	2.0E-07	2.0E-07	2.0E-07	2.0E-07	-
		175000	2.0E-07	2.0E-07	2.0E-07	2.0E-07	2.0E-07
		350000	2.0E-07	2.0E-07	2.0E-07	2.0E-07	2.0E-07
Trenched	Soft	1500	1.8E-09	-	-	-	-
		3600	1.8E-09	-	-	-	-
		10000	1.8E-09	1.8E-09	1.8E-09	-	-
		45000	2.0E-07	2.0E-07	2.0E-07	-	-
		175000	2.0E-07	2.0E-07	2.0E-07	2.0E-07	-
		350000	2.0E-07	2.0E-07	2.0E-07	2.0E-07	2.0E-07
	Hard	1500	-	-	-	-	-
		3600	-	-	-	-	-
		10000	-	-	-	-	-
		45000	2.0E-07	2.0E-07	2.0E-07	-	-
		175000	2.0E-07	2.0E-07	2.0E-07	2.0E-07	-
		350000	2.0E-07	2.0E-07	2.0E-07	2.0E-07	2.0E-07

APPENDIX D

Failure frequencies for pipelines caused by ship foundering

D.1 Failure Frequencies for Pipelines caused by Ship Foundering

This appendix contains background information and a methodology for estimating failure frequencies for subsea pipelines caused by ship foundering and causing damage upon impact to the pipeline on the sea floor.

Methodology

To assess the pipeline failure frequency as result of damage from a foundering ship, the following elements are needed:

- An assessment of ship traffic in a certain area of interest, and
- A methodology to estimate the failure frequency based on ship foundering probability, geometrical considerations and the number of ships crossing the area of interest.

Assessment of ship traffic

To assess the number of ships crossing any given area of interest, Automatic Identification System (AIS) data may be used. Such data can be extracted from various sources. Geographic Information System (GIS) software can be used to define an area of interest and to visualize AIS data in so-called heat maps showing the intensity of ship traffic as a function of location on the map. An example of such a plot is given in Figure D-1.

For any area of interest, detailed AIS data can be extracted which comprises the number of vessel crossings for this area and the identifier of each of the crossings, allowing one to sort by vessel type, vessel dimensions and gross tonnage. Such data would allow one to estimate the "hit probability" as per vessel size category, where it could be assessed that smaller foundering vessels may not have the potential to damage the pipeline.

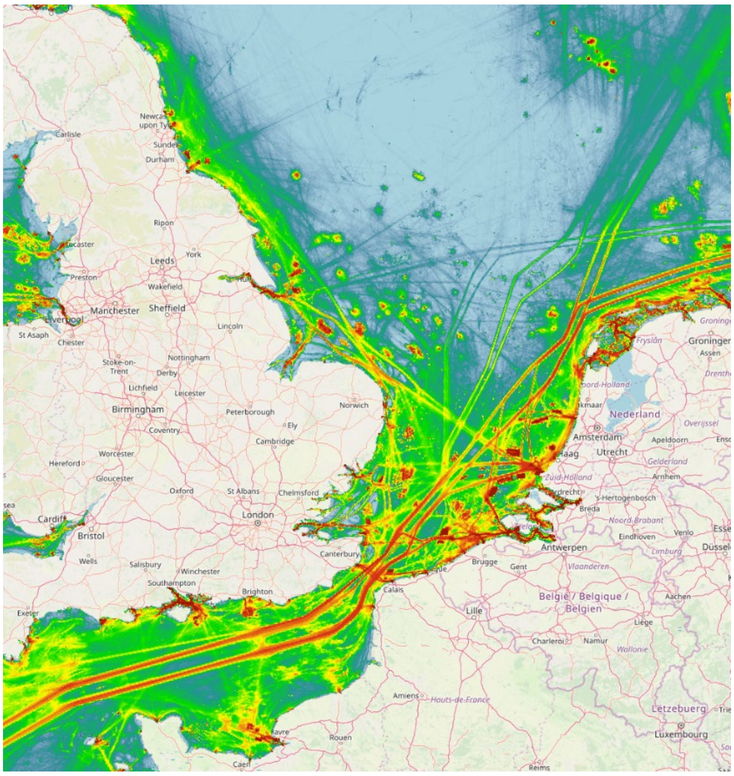

Figure D-1 AIS data showing ship traffic density in the North Sea (source: Kustportaal).

Pipeline failure frequency calculation

The pipeline failure frequency caused by a foundering vessel may be calculated as:

$$F_{failure} = N_{crossings}\ x\ t_{crossing}\ x\ F_{foundering}\ x\ P_{failure}$$

where:

$F_{failure}$	is the pipeline failure frequency [/year]
$N_{crossings}$	is the number of ships crossing the area of interest per year [/year]
$t_{crossing}$	is the average time a vessel needs to cross the area of interest [years]
$F_{foundering}$	is the foundering frequency per ship year [/ship year]
$P_{failure}$	is the probability that a foundering ship hitting the pipeline causing a pipeline failure [-]

The **number of crossings**, $N_{crossings}$, for a given pipeline section, can be obtained from AIS data. For example, a 10-km long stretch of a pipeline can be selected, and the number of crossing AIS-tracks can be retrieved. Not only the tracks but also detailed information on the crossing vessels can be obtained, such as type of vessel and size category.

The **crossing time**, $\mathrm{t_{crossing}}$, can be calculated by assuming an average velocity for crossing vessels, for example 15 kts, and determining the time required to cross the pipeline. This required time can then be calculated through geometrical relations:

$$t_{crossing} = \frac{L + W \tan \alpha}{v}$$

Where *L*, *W* and *v* denote averaged values for ship length, width and velocity in [m], [m] and [m/s], respectively.

The angle α is the angle between the pipeline and the trajectory of the crossing vessel. This angle is 0 degrees for a perpendicular crossing. A 90-degree angle represents a vessel traveling directly above the pipeline along the pipeline trajectory, this is however considered an unlikely situation. In case ships cross the pipeline at random angles it is recommended to select a 45-degree crossing angle. In case AIS data show that the majority of ship traffic crosses the pipeline at a certain angle (major shipping lane) it is recommended to select this angle between the shipping lane and the pipeline as crossing angle.

Note that the probability for the vessel to hit the pipeline is reflected by the crossing time. It is assumed that regardless of the sea depth and how the vessel may sink after a foundering has occurred, the crossing time represents the time needed to travel the distance for which the vessel exposes the pipeline.

The **foundering frequency**, $F_{foundering}$, can be obtained from a fleet incident database, where the type of incident should be set to foundering and the unit should be in incidents per ship year. Based on assessment of worldwide statistics (source: VADIS database, extracted in 2025), a conservative value of 1.0E-03 per ship year is suggested used. If assessed relevant for the project the value can be adjusted by using region-specific statistics for the area of interest.

The **probability that a foundering vessel can cause pipeline failure**, $P_{failure}$, depends on several factors, such as the mass of the ship, the velocity at which it strikes the pipeline, the pipeline burial depth and the pipeline wall thickness. This probability can conservatively be set to 1 for exposed and/or unprotected pipelines. For buried or trenched pipelines, the value will depend on the number of crossings per ship size category. For buried pipelines, it is unlikely that a foundering fishing vessel is able to damage the pipeline. On the other hand, a large cargo ship may penetrate the seabed upon impact, potentially damaging the pipeline despite it being buried. For areas where the ship traffic is dominated by large vessels, it is recommended to set the failure probability to 1. Smaller values can be considered in case of a deep burial depth or the majority of the ship traffic crossing the area of interest being in smaller size categories. The number of crossings per size category can be retrieved from AIS data.

Damage probability and vessel velocity per size category

The damage probability and vessel velocity can be estimated by using an average velocity for all crossing vessels. However, it is likely that smaller vessels have a higher velocity when crossing the pipeline and a smaller probability of damaging it in case of foundering and hitting the pipeline. Thus, if a more detailed assessment is required, it is possible to assess these values per ship size category:

$$F_{failure} = \sum_{n=1}^{n} N_{crossings,n}\ x\ t_{crossing,n}\ x\ F_{foundering,n}\ x\ P_{failure,n}$$

where n indicates the number of size categories used.

Naturally, the ship length and width used in the calculation of $t_{crossing,n}$ can be assessed per size category. The generic foundering frequency, $F_{foundering}$, may be used for all ship categories unless more detailed and robust failure frequencies can be obtained per ship category.

Example

An example including five different vessel categories are presented below. The categories A – E may represent different ship sizes, ship types (e.g. differentiating on vessel speed), and shipping lanes (differentiating on angle of crossing). The resulting pipeline failure frequency from ship foundering, for the section of the pipeline analysed, will be the sum of $F_{failure}$ across all ship categories.

Parameters	**Categories**				
	A	**B**	**C**	**D**	**E**
Vessel Length [m]	60	100	150	200	220
Vessel Width [m]	12	20	30	40	45
Vessel Velocity [knt]	10	15	15	15	15
α [deg]	10	15	45	30	5
$t_{crossing}$ [s]	12	14	23	29	29
$N_{crossings}$ [1/year]	100	1000	500	2500	300
$F_{foundering}$ [1/year]	1.0E-03	1.0E-03	1.0E-03	1.0E-03	1.0E-03
$P_{failure}$	0,5	0,9	1	1	1
$F_{failure}$ [1/year]	1.9E-08	3.9E-07	3.7E-07	2.3E-06	2.8E-07

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