4388

Flexible Pipe Integrity Management Guidance & Good Practice

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JIP Report

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Important Notes

This report forms the key public-domain output from the Sureflex Joint Industry Project (JIP), which ran from 2021 through to 2023. The report provides guidance and good practice relating to flexible pipe integrity management. The guidance and good practice is not intended to directly specify any minimum industry or regulatory requirements. Rather, the authors and JIP steering committee are aligned that any integrity management practices should be risk based, and as such that all "good practice" is not necessarily intended to be applied to all flexible pipes.

The JIP was led by Wood Group UK Ltd throughout the project, with joint input from the 20 industry members which included regulators, manufacturers, and operators / users of flexible pipe. Prior to final publication, the report was subject to a number of revision cycles, firstly with each of the members, and secondly with a wider industry review to selected non-members. Details of the contributing JIP parties, both members and non-members, and the review cycles are summarised in Section 1.4 of the report. Where any comments / feedback from differing parties conflicted, these were reviewed and a position agreed by the JIP steering committee at the final JIP closeout meetings.

In certain parts of the report, principally Section 4.0 in which experience of damage and failure is presented, guidance is distinguished from factual (database) content by the use of sub-headings denoted "Guidance Note", with relevant guidance shown in italics. Similarly, in Appendix B the "Guidance Notes" relating to inspection & monitoring technologies are presented separately from "Industry Practice". It should be noted that guidance is based on the general consensus of opinion across the JIP steering committee and that not all JIP members necessarily agree on all guidance presented herein.

Whilst every effort has been made to ensure the accuracy and reliability of guidance and good practice within the report, it is the responsibility of the user to assess the specific risks relating to each flexible pipe and apply appropriate risk mitigation measures.

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Executive Summary

The Sureflex Joint Industry Project (JIP) is an ongoing initiative focussed on the development and dissemination of integrity management guidance and good practice pertaining to unbonded flexible pipe technology. This latest JIP phase was supported by the largest membership group to date (see Section 1.4) and was completed in 2023.

This report presents a comprehensive update to the previously published Sureflex guidance in 2017, Ref. [13], detailing the latest global flexible pipe population and usage statistics (Section 3.0), experience of damage / failure mechanisms and associated incident rates through time (Section 4.0), and review and comparative evaluation of all known inspection, monitoring and repair technologies and methods (Section 5.0). The primary objective of this report is to assist users of flexible pipe systems in defining good practice integrity management that enable safe and reliable in-service operation.

Unbonded flexible pipe remains an enabling technology in a number of applications, combining a large internal diameter range (up to 20inch) and design pressure (up to 15ksi, 1034bar) capability with an unrivalled bending flexibility that facilitates use in dynamic applications, efficient storage of long product lengths and that can readily conform to uneven pipeline routing. These design features necessitate a multi-layer construction that inevitably results in a wider range of potential failure mechanisms than exist in more traditional homogeneous rigid steel pipelines and a more challenging cross section to inspect for damage or degradation. A thorough understanding of the range, evolution and relative risks of all failure threats is therefore key to users of flexible pipes. Users should carefully consider the applicability of each damage and failure mechanism to their specific flexible pipe system, noting that not all mechanisms are applicable to all systems, and in fact some mechanisms are historic and / or have been mitigated by design improvements.

Unbonded flexible pipe technology was commercialised in the 1970s, therefore may be generally considered as a relatively mature product, with over 20,000 individual pipe sections produced up to the end of 2020. However, almost 1/5th of all pipes have been delivered in the latest 5year period, indicating an increasing volume of use. Furthermore, the pace of technology acceleration in terms of design pressure, diameter, temperature rating, water depth, dynamic service, transported fluid type, thermal requirements etc., has been significant as users of the technology have sought to continually stretch the boundaries of previous experience. Whilst the manufacturers continue to perform product research, development and qualification to meet this demand, this has not prevented the emergence of a number of new failure modes over time and is again evident in the updated failure statistics presented herein.

The Sureflex damage and failure database now records 874 events, 79% of which did not result in pipe loss of containment. However, 147 *Leak* events are reported, and 34 *Rupture* events. These most critical *Rupture* events, with a potential for major accident hazard, are individually described in this report and have exhibited an increased incident rate since 2011. These events have been caused by a relatively small number of failure mechanisms in specific applications, some of which have emerged in the last 5years, as described in Section 2.0. The reported *Leak* and *Damage* rates have in general shown a continual decreasing trend over the last 20 years.

The databases, which are available to members and have been developed over several generations of the JIP, and the corresponding guidance on integrity management and good practice, represent a valuable asset to flexible pipe users. Given the developing nature of applications, and associated challenges, the industry is encouraged to continue the collation and dissemination of experience for the benefit of all users.

Revision History		
Revision	**Date**	**Comments**
01	28/02/2023	Draft edition for JIP member review
02	11/08/2023	Issue for member and non-member stakeholder review
03	06/10/2023	Final check issue to JIP members
04	16/11/2023	Final issue to JIP Members
05	04/12/2023	Issue for industry-wide publication

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Signatory Legend		
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05	Prepared	Ian MacLeod, Technical Director Andrew Moir, Lead Engineer Mark Birmingham, Senior Integrity Engineer
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Table of Contents

List of Figures

List of Tables

1.0 Introduction

1.1 Objective

This report provides up to date industry guidance relating to flexible pipe population and damage statistics, integrity management guidance and good practice. Although some guidance may be common to bonded pipes, the guidance is intended to be specific to unbonded flexible pipes and is focussed on metallic armoured pipe. The report was developed during the latest revision of the Sureflex Joint Industry Project (JIP) between 2021 and 2023. The JIP was widely supported by industry suppliers, operators, and regulators of unbonded flexible pipe systems.

The document provides integrity engineers and managers with a comprehensive review and technical guidance relating to flexible pipe damage and failure mechanisms. The report is supplementary to the national and international codes, standards, and regulatory requirements, and should be used in conjunction with them. It is not intended to specify a minimum standard, as most flexible pipe systems have their unique challenges with specific integrity issues to be addressed. The implementation of any integrity management system should be risk based, so that system-specific requirements can be defined.

This report is not intended to provide an overview or introduction to flexible pipe technology, but rather assumes that individuals reading the report have a general knowledge of the design, manufacture, and operational aspects of flexible pipe. Nonetheless, the document is intended to be standalone with detailed supporting reference documentation to ensure flexible pipe systems are maintained in an efficient working order through effective integrity management.

1.2 Background

Wood issued the proposal for the Sureflex JIP in March 2021, Ref. [66]. The proposal incorporated input from industry pre-kick-off meetings in January 2021, which followed discussions through-out 2020 with industry parties / stakeholders of flexible pipes, who had expressed an interest in re-visiting the previously developed guidance and to update them with more recent experience. The JIP was formally kicked off with virtual meetings on 11th and 12th August 2021.

The Sureflex JIP builds upon a historic program of work which dates back to the late 1990s, as follows in reverse chronological order:

- 2017 - Sureflex JIP developing the previous iteration of this *Flexible Pipe Integrity Management Guidance & Good Practice* deliverable, published through Oil & Gas UK, Ref. [13],
- 2010 - original Sureflex JIP, with output deliverables published through Oil & Gas UK, Ref. [14] & [15],
- 2002 - JIP studies relating to flexible pipe integrity & inspection / monitoring, with output deliverables published through UKOOA, Ref. [17] & [18],
- 1998 - flexible pipe integrity & inspection / monitoring JIP, resulting in publication of HSE technology reports OTO98018 & OTO98019, Ref. [19] & [20].

1.3 JIP Approach & Methodology

The JIP scope of work and objectives are summarised in the original proposal (Ref. [66]).

Input to the JIP was sourced from the following means:

- Population and Damage & Failure databases prepared as part of the last JIP revision (Ref. [13]).
- Manufacturer supplied pipe inventory since the completion of the last JIP revision.
- Degradation, damage and failure experience / events from JIP members, non-members and 3rd parties.
- Inspection, monitoring, maintenance and repair technology vendor presentations and industry review.
- Published papers on flexible pipe integrity, research and development.

The JIP has collated and analysed the global flexible pipe data to generate a picture of the quantities and types of flexible pipe in use, the numbers and type of damage / failure incidents and the failure modes experienced. This work has been performed such that the data is non-attributable in order to maintain confidentiality.

This document is intended to discuss in generic terms the general structural characteristics and integrity features of the pipe without discussing relative merits and sometimes subtle differences between manufacturers. No inference should be made by the reader on the performance or reliability of any specific flexible pipe manufacturer. Indeed, a key success of the JIP has been to retain the engagement of the main three manufacturers of unbonded flexible pipe as active members of the project. The willingness of the manufacturers to collaborate with industry users of flexible pipe through the project is to be commended.

1.4 JIP Participants

The JIP has been supported by a wide spectrum of bodies involved with the integrity management of flexible pipe, with an increased membership and global footprint. In addition to the support of the JIP members, a number of additional parties contributed data and time to the JIP at various stages of the project as acknowledged in the following sections.

1.4.1 Members

Operators of Flexible Pipe	BP, Chevron, CNRI, Equinor, ExxonMobil, Harbour Energy, Inpex, Petrobras, Petronas, PetroRio, Santos, Shell, Woodside
Flexible Pipe Manufacturers	Baker Hughes, NOV, TechnipFMC
Regulatory Authorities	Agência Nacional do Petróleo, Gás Natural e Biocombustíveis (ANP) – Brazil, Health & Safety Executive (HSE) – UK, National Offshore Petroleum Safety and Environmental Management Authority (NOPSEMA) – Australia, Petroleum Safety Authority (PSA) – Norway

1.4.2 Non-Member Contributors

In addition to the membership, there were contributions to the JIP from a number of non-member organisations. These included damage and failure experience (which was incorporated into the JIP database) and / or the provision of comments on the initial revisions or relevant subsections of the JIP report. The key contributors are summarised as follows:

Operators of Flexible Pipe	ADNOC, AkerBP, Neptune Energy, TotalEnergies, Wintershall Dea
Industry Bodies	Energy Institute
3rd Party Contractors	2H, 4Subsea, Arkema, Evonik, Flexlife

1.4.3 Inspection, Monitoring, Maintenance and Repair Vendor Contributors

A number of vendors presented their latest flexible pipe technologies at a series of workshops as part of the JIP. The output from the workshops and subsequent engagement with additional vendors is summarised in Section 5.0 of this report. The JIP is grateful for the support and input from the following vendors:

- 4Subsea, Aisus/DXE, Baker Hughes, Balmoral, CRP, FlexLife, FlexTech, InnetiQs, Kongsberg, NOV, OuroNova, Pulse, Simeros, Subsea Energy Solution, TechnipFMC, TechnipEnergies, TRAC, Tracerco, Wood.

1.5 Abbreviations

AUV	Autonomous Underwater Vehicle
CODAM	Database for damage to structures and subsea facilities (Norwegian)
CP	Cathodic Protection
CVI	Close Visual Inspection
DBB	Double Block and Bleed (valve assembly)
DPxID	Design Pressure times Inner Diameter product
DT	Digital Twin
ESDV	Emergency Shutdown Valve
FAT	Factory Acceptance Test
FBG	Fibre Bragg Grating
FEED	Front End Engineering Design
FFS	Fitness for Service
FLIP	Flow Induced Pulsation
FMECA	Failure Mode, Effects and Criticality Analysis
FNF	Fatigue Notch Factor
FoS	Factor of Safety
FPSO	Floating Production Storage Offloading (vessel)
FPU	Floating Production Unit

GRV	Gas Relief Valve
GVI	General Visual Inspection
HIC	Hydrogen Induced Cracking
HSE	Health and Safety Executive (UK regulatory body)
ID	Inner Diameter
ILI	In-Line Inspection
IMS	Integrity Management Strategy
IPS	Internal Pressure Sheath
ITPE	Improved Temperature Polyethylene
JIP	Joint Industry Project
KPI	Key Performance Indicator
ksig	Thousand pounds per square inch (gauge pressure)
LASER	Light Amplification by the Stimulated Emission of Radiation
LoC	Loss of Containment
LTI	Lost Time Injury
m	Metres
MAH	Major Accident Hazard
MAOP	Maximum Allowable Operating Pressure
MAPD	Major Accident Prevention Document
MBR	Minimum Bend Radius
MIC	Microbially Induced Corrosion
MWA	Mid Water Arch
NCR	Non Conformance Record
NDT	Non Destructive Test(ing)
NRV	Non Return Valve
OLT	Offshore Leak Test
OREDA	Offshore Reliability Data (independent forum for collection of O&G reliability data)
PA	Polyamide
PARLOC	Pipeline and Riser Loss of Containment, see Ref. [71]
PE	Polyethylene
PFP	Passive Fire Protection
PLEM	Pipeline End Manifold

PLET	Pipeline End Termination
PLUG	Pipeline Users Group
ppm	parts per million
PRCI	Pipeline Research Council International
PRV	Pressure Relief Valve
PSA / PTIL	Petroleum Safety Authority (Norway regulatory body) / Petroleumstilsynet
PSR	Pipelines Safety Regulations (UK regulations, Ref. [68])
PU	Polyurethane
PVDF	Polyvinylidene Difluoride
QA	Quality Assurance
QC	Quality Control
RCFA	Root Cause Failure Analysis
ROAV	Remotely Operated Aerial Vehicle
ROV	Remotely Operated Vehicle
SN	SN Curve, Stress / Number of Cycles to Failure, characterising material fatigue performance
SCC	Stress Corrosion Cracking
SSC	Sulfide Stress Cracking
SSIV	Subsea Isolation Valve
SUT	Society for Underwater Technology
Te	Tonne (1000kg)
TLP	Tension Leg Platform
TRL	Technology Readiness Level
UKCS	United Kingdom Continental Shelf
UT	Ultrasonic Testing
UV	Ultra Violet
XLPE	Crosslinked Polyethylene

1.6 Flexible Pipe Layer Definitions

The generic definitions, as shown in Figure 1.1, are applied to unbonded flexible pipe layers throughout this report, which are aligned with the terminology used in API RP 17B, Ref. [1]. Other definitions utilised through the report are presented in Appendix A.

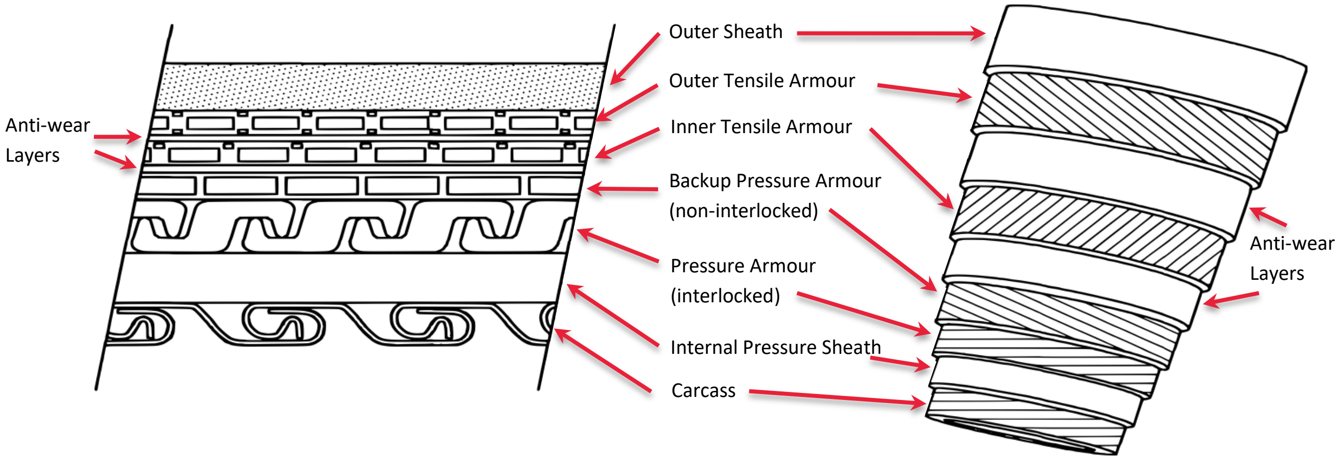


Figure 1.1 Unbonded Flexible Pipe Cross Section, Ref. [1], API RP 17B, images

Notes:
1. Not all layers are always utilised in every pipe construction. For example;
   - Product Family I – Smooth Bore Pipe excludes the carcass but normally includes an additional intermediate "anti-collapse" sheath.
   - Product Family II – Rough Bore Pipe excludes the independent Pressure Armour layer, with both hoop and axial loading being restrained by the tensile armours, wound at a (higher) balanced lay angle, i.e. 55°.
   - The (non-interlocked) backup pressure armour is not always utilised.
   - Anti-wear layers are traditionally not utilised in pipe which is designed for static service.
   - Some manufacturers continue to develop and offer flat-strip (non-interlocked) pressure armours for more benign applications.
2. Additional layers are sometimes utilised, which are not shown. For example;
   - Insulation layers (wrapped) may be included, either between two extruded polymer layers or, directly onto the outer tensile armour layer.
   - An additional external protective sheath may be included, sometimes over only specific lengths of pipe to increase pipe stiffness and / or increased robustness to external wear in service. Additional mechanical protection (e.g. fabric / high strength tapes, thermal insulation etc.) may also be incorporated between the outer sheath and the secondary protective sheath.
3. The annulus is defined as the region between the internal pressure sheath and the outer sheath directly outside the tensile armour wires. Where an additional extruded layer is included and sealed within the end fitting, a secondary annulus may be formed.

2.0 Key Findings & Conclusions

2.1 Conclusions

1. The JIP has collated historical population statistics relating to every flexible pipe manufactured by Baker Hughes, NOV, and TechnipFMC up to the end of 2020. To date, a total length of ~18,500km of unbonded flexible pipe has been supplied, comprised of ~20,500 individual pipe sections. The detailed population database enables an improved ability to assess risk relating to damage and failure mechanisms. Full details relating to the population statistics are presented in Section 3.0 of this report.
2. The total inventory has increased by 18% (based on supplied length) since the last JIP iteration, indicating that flexible pipe remains an enabling and competitive technology for a range of applications. The calculated operational experience per year continues to grow, although the rate of increase is slowing as the industry matures and an increasing number of retired pipes take greater effect on the operational statistics.
3. The JIP continues to collate, document, and share information relating to *Damage* and *Failure* of unbonded flexible pipe and presents this information in a database, which is available to the JIP members. The database identifies a total of 874 individual incidents, as detailed in Section 4.0. Of these incidents:
   a. 693 cases of degradation which did not result in a *Leak* or *Rupture*
   b. 147 cases which resulted in a *Leak*
   c. 34 cases which resulted in a *Rupture* (as described in Section 4.5)
4. The detailed population and damage / failure information enable the calculation of failure rate statistics. However, caution should clearly be applied in the use of this data to determine incident probabilities given that the database may not be exhaustive and that each flexible pipe tends to be a bespoke supply. As such, the high-level statistics fail to take account of individual system differences which influence pipe performance and likelihood of failure, as described Section 4.1. Therefore, the application of derived failure rate statistics must be carefully considered when used to provide input to support operational risk-based decisions.
5. Figure 4.10 and Figure 4.11 additionally distinguish *Damage* and *Failure* incidents in the last 5 and 10year reporting periods as subsets of the full dataset, to identify which mechanisms are prevalent / emerging, and those that are largely historical and / or have been mitigated through design improvements. Furthermore, Appendix D includes alternative damages and failure rates which omit incidents not directly linked to the flexible pipe system itself e.g. mishandling during installation / handling, maloperation, 3rd party interaction, abnormal accidental / extreme weather events not accounted for in design.
6. Further to Conclusion #4, the Sureflex JIP has developed damage / failure rate statistics relating to the entire population. These *Damage* and *Failure* incident rates are presented in Table 4.14, with the incident rates per pipe-year relating to the latest 5-year period being:
   - Damaged — Risers, 2.18E-03 — Flowlines & Jumpers, 9.84E-05
   - Failure – Leak — Risers, 2.79E-04 — Flowlines & Jumpers, 1.18E-04
   - Failed – Rupture — Risers, 5.58E-04 — Flowlines & Jumpers, 5.91E-05
   - **All Damage/Failure — Risers, 3.01E-03 — Flowlines & Jumpers, 2.76E-04**

   It should be noted that the incident rates relating to this most recent period intuitively exclude mechanisms / events recorded prior to 2016.
7. Flexible pipe incident failure rates are not all in a stable equilibrium or showing a declining trend, as shown in Table 4.14. Whilst the Failure-*Leak* incident rates continue to decline, the Failure-*Rupture* incident rates for *Riser* applications have shown a significant increase in the last decade.

8. Several newly emergent failure modes have occurred since the last JIP phase concluded, and importantly these mechanisms have resulted in *Rupture* events, where appropriate mitigations were not in place. These emergent modes include;
   - Stress corrosion cracking of armours due to CO_2 (rapid failure mode),
   - Corrosion failures due to atmospheric backflow (air-breathing vents),
   - Additional fatigue / corrosion-fatigue failures in the main pipe section, due to new contributory factors including; deficient bend stiffener interfaces, and weather-vaning turret seizure.

   Significant design engineering and qualification efforts are undertaken as new flexible pipe applications push the boundaries of experience. However, these emergent failures have occurred, and the industry is working hard to react and close these gaps (see Conclusion #14).
9. There has been a significant increase in the number of the most severe *Rupture* events reported since the completion of the last JIP phase. These principally relate to the points in Conclusion #8, plus a significant number of fatigue events related to high contact loading at the bend stiffener interface, corrosion / cracking on un-reinforced 55° armour designs, and a sweet pipe operated in sour service application. Up to the end of the last JIP phase (Ref. [13]), there were a total of 10 reported *Ruptures*. The total is now 34 *Ruptures*, although some newly reported in this phase are historic. Table 4.18 presents details of all reported such events and associated failure mode mitigations.
10. Whilst there are a range of reported failure mechanisms, industry experience also indicates flexible pipes often exhibit a good degree of robustness and structural capacity, under a number of abnormal conditions, including some not considered in design. Moreover, the root cause of reported failures tends not to be associated with extreme design / storm events. Some recent specific examples of abnormal loading include;
    - Riser recoveries (prior to failure) with significant numbers of broken armour wires, e.g. 19 of 55 in a single layer (35%) in excess of the number predicted by inspection.
    - Riser system survival (and reinstatement) following Mid Water Arch (MWA) up-ending (Ref. [74]).
    - Riser integrity maintained following operation with undetected bend stiffener losses in a harsh environment.
    - Survival from anchor dragging incidents over flowlines and risers, and subsequent successful structural integrity tests (24hours and 1.25 times design pressure) enabling continued operation.
    - Dynamic risers exposed to temperatures far in excess of design for ~2hours following topsides cooler failure. Subsequent testing and monitoring assessed potential for degradation. Risers remain in service 5years later.
    - Increasing number of flexible pipes where life extension assessments have been performed and continued operation approved.

    Additional historic events, including those reported in Ref. [13];
    - Mooring system failure, large displacement of riser bases, with the absence of any flexible riser LoC.
    - Large dropped objects (i.e. 8.5Te, and 24Te) impacting on flexible pipe near host facilities, where investigation / analysis / assurance allowed the pipes to re-enter service.
    - Additional MWA system failures resulting in either multiple risers being dropped onto the seabed and / or significant abnormal loading, and subsequent re-instatement.
    - Undetected loss of hold-down anchor leading to very low MBR at subsea interace (likely beyond static MBR). Anchor reinstated, subsequent leak test, and riser remained in service to end of field life.
    - Redundancy in the cross section of a flexible pipe, including a riser being identified with 15 adjacent tensile armour wires failed, prior to repair and re-instatement (Ref. [25]).

11. Inspection, monitoring, maintenance and repair technologies have been reviewed as part of this JIP phase, capturing new methods and experience, i.e. updated technology readiness level (TRL), industry take-up, and user feedback. These findings relating to all identified technologies are detailed in Section 5.0, and summarised in Figure 5.1. Appendix B contains detailed guidance on each method.
12. Flexible pipe remains a challenging product to reliably inspect and the effectiveness and practicality of performing condition assessment is typically dependent on a number of specific factors, including the failure mechanism, method / technology, pipe cross section, access constraints and the overall pipe system design. Whilst there have been important developments of existing and new technologies since the publication of Ref. [13], further work to improve the reliability, ease of deployment and usability is required, particularly for those methods which are specifically targeted at establishing the condition of the strength bearing armour layers. Knowledge and experience sharing of inspection method success and failure is key to ensuring that appropriate and relevant guidance is maintained and made available to the wider industry.
13. A summary of flexible pipe system integrity management good practice and lessons learned, by life cycle phase, is presented in Section 6.0. It is evident from the emergent failure mechanisms that have occurred in recent years (see Conclusion #8) that operators need to maintain a vigilance to unforeseen or novel undocumented threats. This is particularly the case for pipe applications that stretch the boundaries of previous experience and where enhanced mitigations in terms of qualification, testing or in-service inspection and/or monitoring may be necessary.
14. Where emergent integrity threats or identified operational challenges have arisen, the wider flexible pipe industry, including manufacturers, operators, regulators and consultancy organisations have actively responded, as per the specific examples below;
    - Stress corrosion cracking of armours due to CO_2, including new JIP proposal, see Section 8.3,
    - Development and qualification of anti-FLIP carcass designs, see Section 4.1.2.1,
    - Increased offering of integrated monitoring capabilities, see Section 9.4,
    - Development of new / updated codes / industry standards and guidance, including;
        a. Updates to various API standards; 17L1/L2 completed (Ref. [5], [2]), 17J/B ongoing (Ref. [4], [1]), and JIP-led update of 17TR2 (Ref. [6]), see also Section 8.5,
        b. Development of Energy Institute guidance on flexible pipe system life extension, Ref. [21],
    - Various additional supporting JIPs and initiatives. These are detailed in Section 7.0 (relating to manufacturer R&D efforts) and Section 8.0 (other JIPs / forums).

2.2 Recommendations

The key recommendations from the JIP are as follows:

1. The guidance presented herein relating to the global experience of flexible pipe usage, damage, and failure should be considered when assessing threats and mitigations. It is recommended that a risk-based integrity management program is developed and implemented that accounts for the relevant threats to each flexible pipe system.
2. Further to Conclusion #8, specific care should be taken to ensure riser topside vent systems prevent atmospheric backflow to mitigate the potential for corrosion failure, as per guidance in Figure 6.2.
3. The statistics gathered as part of the JIP should be maintained to provide an ongoing understanding of technology advances and trends in damage and failure statistics. Appendix E of this report presents a standardised reporting template for flexible pipe damage and failure. Furthermore, it is recommended as good practice that in cases of emergent failures or cases with the potential for high impact / consequence that the flexible pipe manufacturer is consulted and a root cause failure analysis (RCFA) is performed.

3.0 Flexible Pipe Database : Population Statistics

3.1 Objective & Approach

The flexible pipe database population statistics are maintained in order to understand the general trends relating to flexible pipe use, and to support the quantification of risks relating to *Damage* and *Failure* of flexible pipe (ref. Section 4.0 of this report).

The approach to updating the population database was to collate data from each of the flexible pipe manufacturers relating to their total historical supply of flexible pipes. This provides the most comprehensive population statistics for the global supply of flexible pipes and is consistent with the approach adopted in the previous phase of the Sureflex JIP (Ref. [13]). The dataset does not include any non-metallic armoured pipe.

All the manufacturer members provided the following parameters for each supplied flexible pipe:

- Flexible pipe type e.g. Risers; Static or Dynamic, Flowlines, Jumpers
- Product use e.g. Gas Lift, Gas Injection / Disposal, Gas Import / Export (separated), Oil Import / Export (separated), Production (multiphase oil), Production (gas / condensate), Water Injection, Test, Other
- Supply date
- Field water depth
- Design pressure
- Design temperature
- Inner diameter
- Flexible pipe length
- Number of identical pipe sections
- Rough / smooth bore
- Internal pressure sheath material
- Sweet / sour service

The individual manufacturer's experience is then collated into a single global database. The key outputs from the database are included in the following sections of this report.

3.2 Database Limitations

The population database is the most comprehensive global database of unbonded flexible pipes and utilises the manufactured inventory from suppliers. However, there are some minor limitations / weaknesses as summarised below:

- When endeavouring to retrospectively collate historical data, the full details for every manufactured pipe were not always available from all suppliers. For example, out of the total number of 10,147 line items in the database, the missing data is as follows;

Parameter	Supply Date	Design Pressure	Design Temperature	Inner Diameter	Sweet / Sour Service
Missing Data	~0.9%	~5%	~26%	~0.1%	~3%

These gaps represent a relatively small proportion of the data set and are predominantly from the emergent years of use when applications tended to be less onerous. Wherever data is presented in this report, the actual size of the population for the relevant figure is specified.

- In some cases, the date information from the different suppliers relates to contract award date and for others the delivery / supply date. As such, whilst some of the presented "timeline" information may appear irregular, this is likely to be the result of slightly varying input data parameters. However, the overall trends are valid and blended into 5-year blocks for subsequent analysis.
- The suppliers typically receive limited feedback from the users of flexible pipe relating to when pipes are installed, recovered, cease operation, or retired. In addition, not all damage / failure events are notified to manufacturers. As such, the supplier's data does not accurately reflect the "as-installed" operational population. To account for this difference, adjustments are made to the "as-supplied" data using adjustment factors based on the age of the supplied pipe, as detailed in Section 3.6.1.

3.3 Population Summary Statistics

The total inventory of flexible pipes included within the database is detailed in Table 3.1.

Table 3.1 Population Database, Total Supplied Inventory (unadjusted)

Pipe Type	Total Flexible Pipes Supplied				Average Pipe Section Length
	Sections of Pipe		Length		
	(number)	(% of total)	(km)	(% of total)	(metres)
Riser – Static	301	1.5%	281.7	1.5%	936
Riser – Dynamic	5,623	27.3%	4,203.3	22.6%	748
Riser (unspecified)	73	0.4%	21.1	0.1%	289
Flowlines	10,191	49.5%	13,209.1	71.1%	1,296
Jumpers	3,679	17.9%	478.6	2.6%	130
Unspecified	716	3.5%	385.9	2.1%	539
Totals (average)	**20,583**	**100.0%**	**18,579.7**	**100.0%**	**903**

Notes: 1. Data presented for all pipe where data relating to both *pipe length* and the *number of sections* was supplied.

3.4 Flexible Pipe Development through Time

The concept of flexible pipe technology dates back to 1944 when 3-inch flowlines were used to transfer fuel from England to France. From the late 1960s a limited number of pipes were commercialised in low pressure smoothbore flowline applications for drinking water and chemical transfer. However, the commercialisation of flexible pipe technology in its current form began in the early 1970s, and the population database statistics presented herein refer to the industry experience from this time.

The population database thus captures over 45 years of flexible pipe manufacturing experience, and the advancements of the technology capability is presented in this section.

Whilst the design parameters of the supplied pipe do not necessarily reflect how any pipe is operated, it is useful to understand the trends in these parameters over time. In addition, **users of the data in this report should be aware that the subsequent data do not represent product capability limits, but instead reflect the manufacturer's response to evolving operator requirements**.

In this JIP revision, additional trends (5-year averages) for many of the pipe design parameters are calculated and overlaid on the historic timeline charts. The 5-year average parameters are weighted based on the supplied length of individual pipe sections, as shown on the timeline charts in Figure 3.1 to Figure 3.15. All design parameters show a clear increase over time based on the supplied inventory as operators pursue applications with more challenging conditions, as follows;

- Whilst the overall range of pipe **inner diameter** in the preceding 5 years since the last JIP has not changed (1 to 19 inches, 25.4 to 482.6mm), the 5-year average pipe ID does show a gradual increase to larger diameters throughout the historical timeline (Figure 3.1) e.g. less than 6inch up to mid 1990s and now approaching 7inch. The continuing increase over the latest 5-year period is also reflected in the histogram (Figure 3.2) where the larger diameter ranges show increasing population percentages, and the smaller diameter ranges typically show reducing percentages when adding the latest 5-year dataset. Considering the larger diameter pipe sizes, it is noted that whilst 7.4% of all pipes ever supplied have a diameter over 10inches, pipes of this size account for 10.0% of pipes added in the latest 5-year block.
- Pipe **design pressure** (Figure 3.3) and **design temperature** (Figure 3.4) both show an increase of the supplied population experience as designs have evolved to meet the demands of operators. Whilst there appears to be an anomaly with an excessively high weighted average design temperature for the 1980-1985 period, this is a result of relatively sparsely populated temperature data in the early years in combination with higher temperature designs of longer length flowlines in a single year (1985). The average design pressure has increased significantly from ~200barg prior to 1990 to 332barg in the latest 5-year dataset.
    - Figure 3.5 additionally presents the average design temperatures for all pipes compared to the equivalent trend for the subset of Polyamide (PA) internal pressure sheath pipes only. As noted in Section 4.4.4, whilst there were a number of PA related thermal ageing (hydrolysis) failures in the late 1990s leading to the introduction of API 17TR2 in 2003, Ref. [6], the design temperature histories of PA pipes in isolation do not significantly differ from the trend for all pipes over time. This is due to the fact that the thermal ageing effects of PA is time-based, so short-term operations at higher design temperatures may still be acceptable though long-term operating temperatures should be lower. Figure 3.6 further presents a histogram of the design temperature of PA pipes supplied over the last 10year period only, which confirms that 60.6%

of those pipes have a design temperature in the range 80 to 90°C (with >95% of these having a design temperature equal to 90°C). Whilst short-term operation in a wetted environment, or longer term exposure for dry gas transfer, may be acceptable for PA pipes at the design temperature of 90°C, API 17TR2 indicates that long-term operational exposure to such high temperature in wetted environments is likely to lead to degradation / failures such as those experienced in the late 1990s.

- The **design water depth** 5-year averages (Figure 3.7 show a continuous and significant increase, with a step change in the last 5-year period from 1,124 to 1,448 metres. As noted up front, these trends are not a measure of manufacturer capability, and in addition may be affected by large supply contracts and multi-section deepwater pipes, where a common (maximum) depth requirement is specified. The corresponding histogram (Figure 3.8) shows increases in deepwater applications in the recent period and a corresponding decrease in the shallower depth ranges, as follows;
  - Water depths ≥2,000m account for 14.6% of all pipes (8.5% in the previous JIP report)
  - Water depths <500m account for 50.1% of all pipes (54.0% in the previous JIP report).
- As a measure of pipe strength, the timeline of the **product of design pressure and inner diameter** is presented in Figure 3.9, with a corresponding histogram (Figure 3.10) again showing the change when considering the last 5-year dataset. For this parameter, the average figure has increased markedly (~140%) from ~13ksi-inch prior to 1990 to >31ksi-inch in the latest 5-year dataset. The maximum P x ID product of all pipes ever supplied is 90ksi-inch, supplied in the latest 5-year period, demonstrating the increased strength capability. However, 79.9% of all pipes ever supplied have a product value of less than 35ksi-inch.
- In Figure 3.11, the design requirement for a **sweet / sour material capability** are presented as 5-year averages from the earliest dataset where >90% of supplied pipes were for a sweet service design, to the current period where >60% adopt a sour service requirement with the associated material challenges.

In addition, the timeline trends for the following parameters are presented;

- Figure 3.12 shows the proportion of **smooth bore / rough bore** pipes supplied i.e. pipes without / with an internal carcass. This shows that rough bore pipes represent the significant majority of supplied pipes, over 85% in each of the 5-year periods to date. Over all the periods combined, rough bore pipes account for 90% of all supplied pipes.
  - Figure 3.13 gives a breakdown of pipe product use into six consolidated groups, and Figure 3.14 presents the corresponding split of smooth bore / rough bore applications for each of these groups. The majority of these six groups are significantly dominated (each >96%) by rough bore products. As expected, the key outlier is for pipes in water service, where 64% of supplied pipes are smooth bore (the corresponding subsets for Risers and Flowline&Jumper applications have smooth bore designs for 51% and 68% of supplied pipes).
- Figure 3.15 shows the proportion of pipes utilising the key **internal pressure sheath polymer** types over time. In the early years, PA (polyamide) grades are utilised almost exclusively, followed by the progressive introduction of PE (polyethylene) / PVDF (polyvinylidene difluoride) / XLPE (crosslinked polyethylene) & Improved Temperature PE (ITPE) grades in subsequent time periods. The dataset shows the varying material usage as follows;
  - in the latest 5-year period; 42% PA / 9% PE / 30%PVDF / 19% XLPE/ITPE
  - over all time periods shown in Figure 3.15; 54% PA / 13% PE / 24%PVDF / 9% XLPE/ITPE

Finally, Figure 3.16 shows the percentage distribution of internal pressure sheath material groups by design temperature range over the last 10year period only. Figure 3.17 shows the total number of pipes per design temperature range for the same dataset. Table 3.2 shows the corresponding data in tabular form.

Table 3.2 Internal Pressure Sheath Material per Design Temperature Range (last 10 years only)

Design Temperature Range (°C)		Number of Flexible Pipes					% distribution			
From	To	PA	PE	PVDF	XLPE / ITPE	Total	PA	PE	PVDF	XLPE / ITPE
>0	<=10				1	**1**				100.0%
>10	<=20	1	8	3	2	**14**	7.1%	57.1%	21.4%	14.3%
>20	<=30	7	24	32	5	**68**	10.3%	35.3%	47.1%	7.4%
>30	<=40	60	59	6	14	**139**	43.2%	42.4%	4.3%	10.1%
>40	<=50	49	101	3	22	**175**	28.0%	57.7%	1.7%	12.6%
>50	<=60	362	381	15	52	**810**	44.7%	47.0%	1.9%	6.4%
>60	<=70	268	90	60	234	**652**	41.1%	13.8%	9.2%	35.9%
>70	<=80	301	41	72	286	**700**	43.0%	5.9%	10.3%	40.9%
>80	<=90	1646	31	625	281	**2583**	63.7%	1.2%	24.2%	10.9%
>90	<=100	17	2	338	28	**385**	4.4%	0.5%	87.8%	7.3%
>100	<=110		1	242		**243**		0.4%	99.6%	
>110	<=120	3		159		**162**	1.9%		98.1%	
>120	<=130			479		**479**			100.0%	
>130	<=140			5		**5**			100.0%	
>140	<=150			2		**2**			100.0%	
Total		**2714**	**738**	**2041**	**925**	**6418**				

Notes: 1. Internal Pressure Sheath materials are grouped as follows;

- PA polyamide
- PE polyethylene
- PVDF polyvinylidene difluoride
- XLPE/ITPE crosslinked polyethylene / improved temperature PE

2. Conditional formatting is used to show the relative % distributions / weightings for design temperature ranges which are statistically significant (over 100 pipe sections).

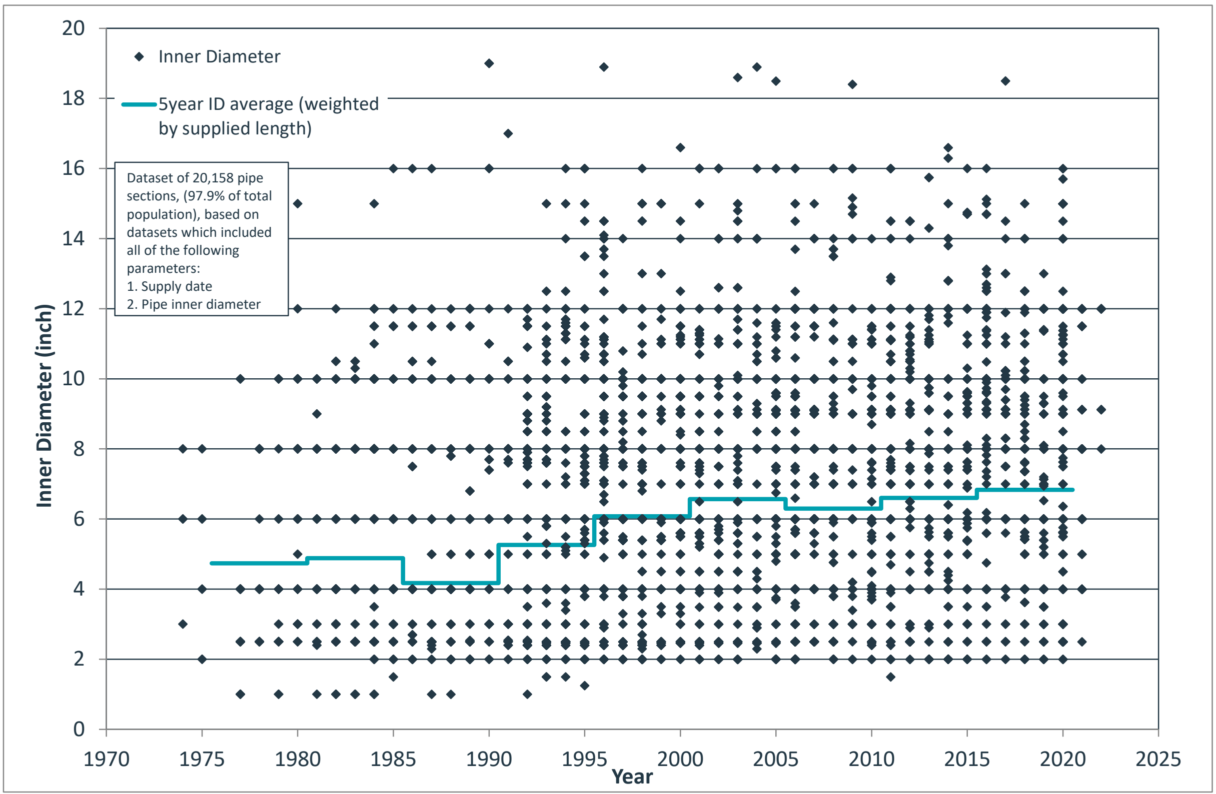


Figure 3.1 Pipe Inner Diameter (inch) Timeline

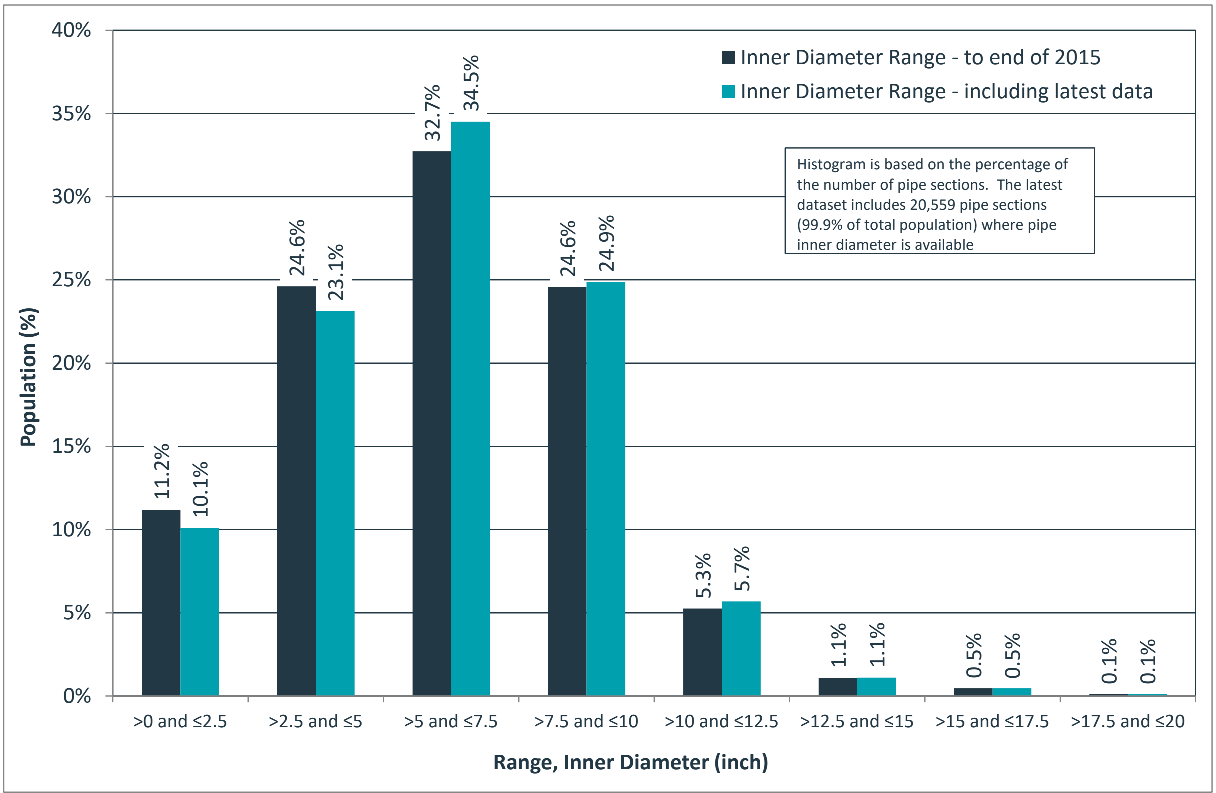


Figure 3.2 Pipe Inner Diameter (inch) Histogram

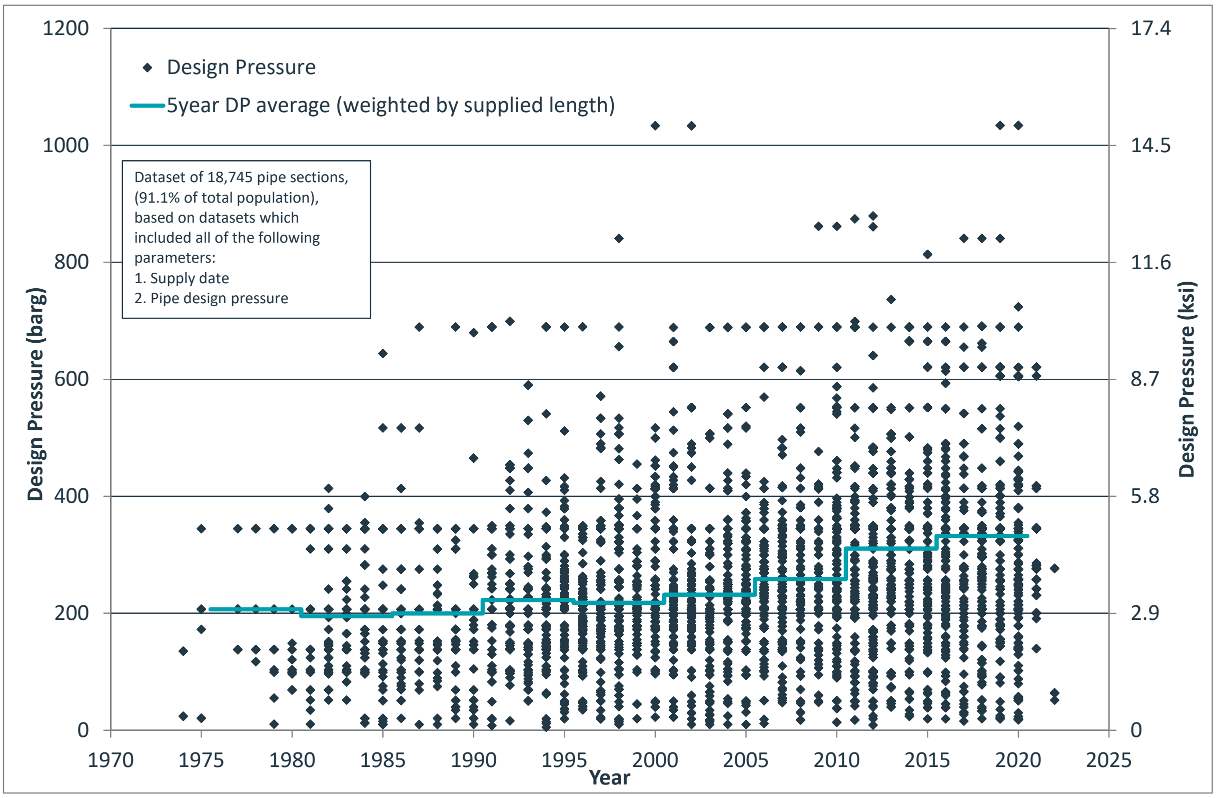


Figure 3.3 Design Pressure Timeline

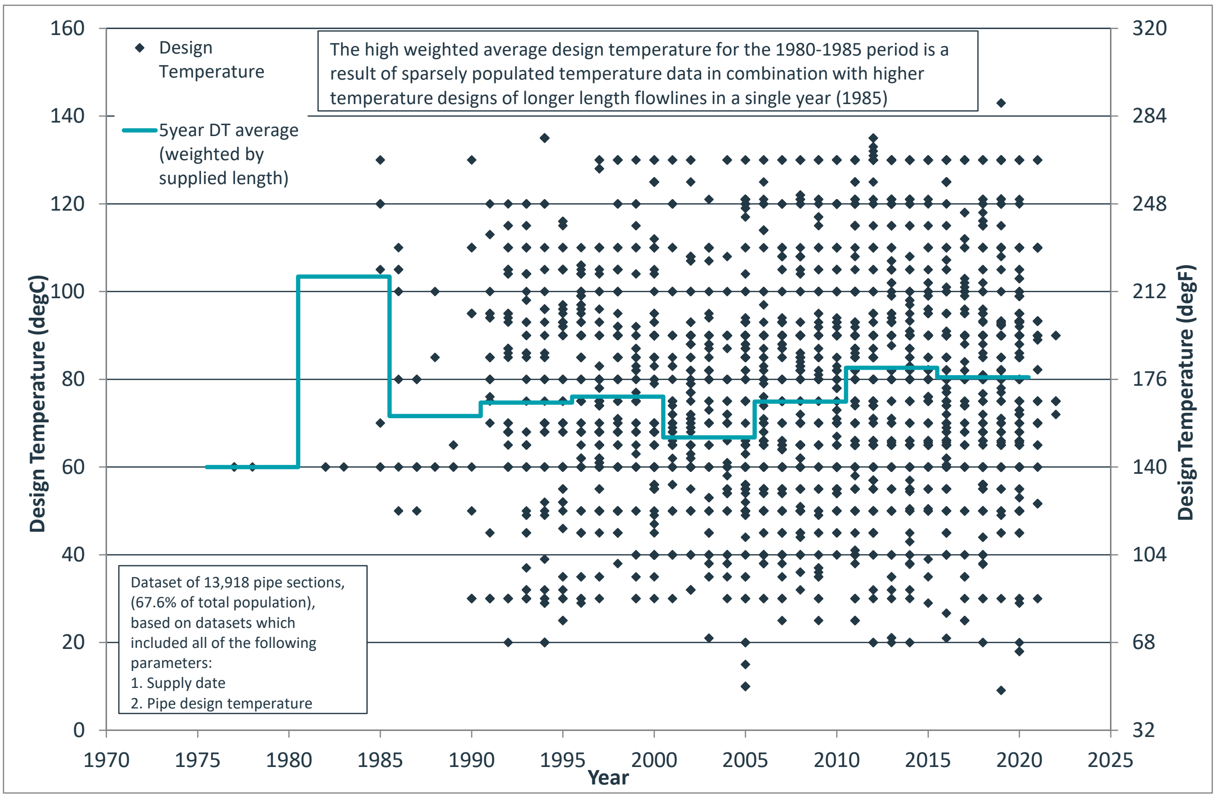


Figure 3.4 Design Temperature Timeline

wood.

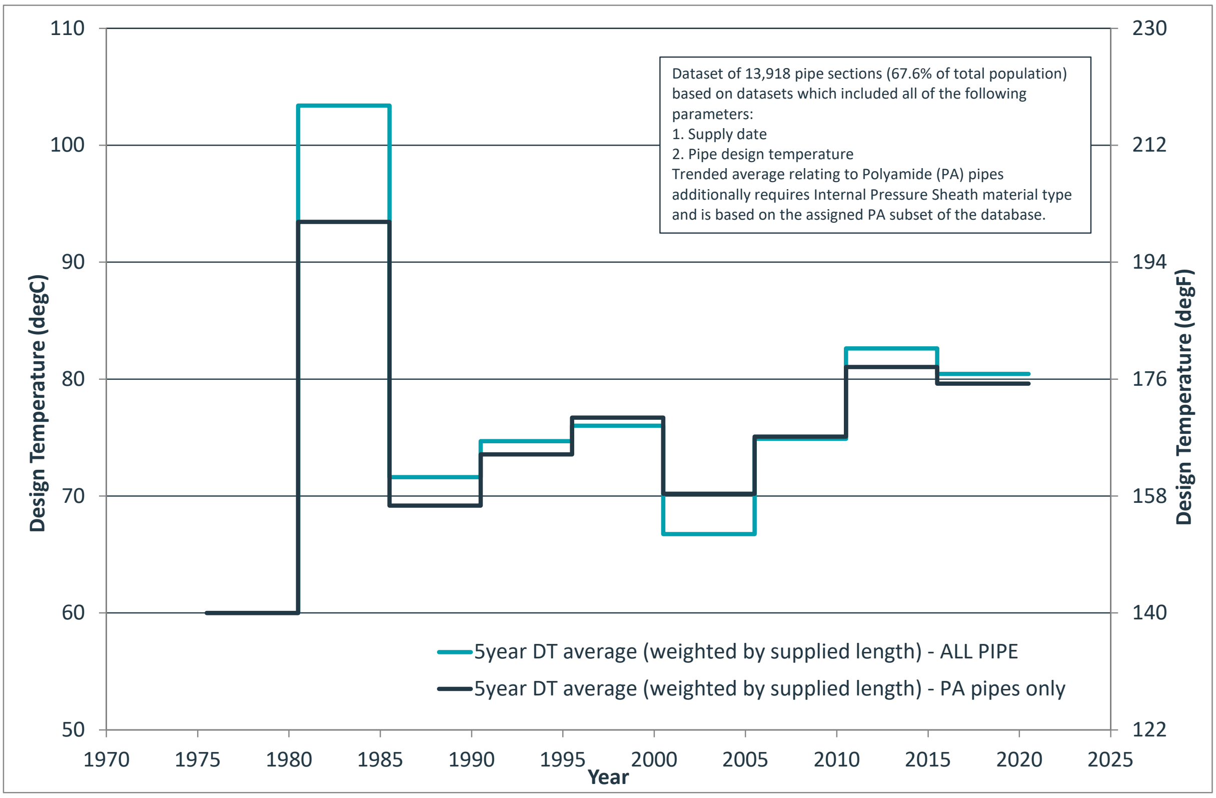


Figure 3.5 Weighted Average Design Temperature – All pipe vs PA pipes only

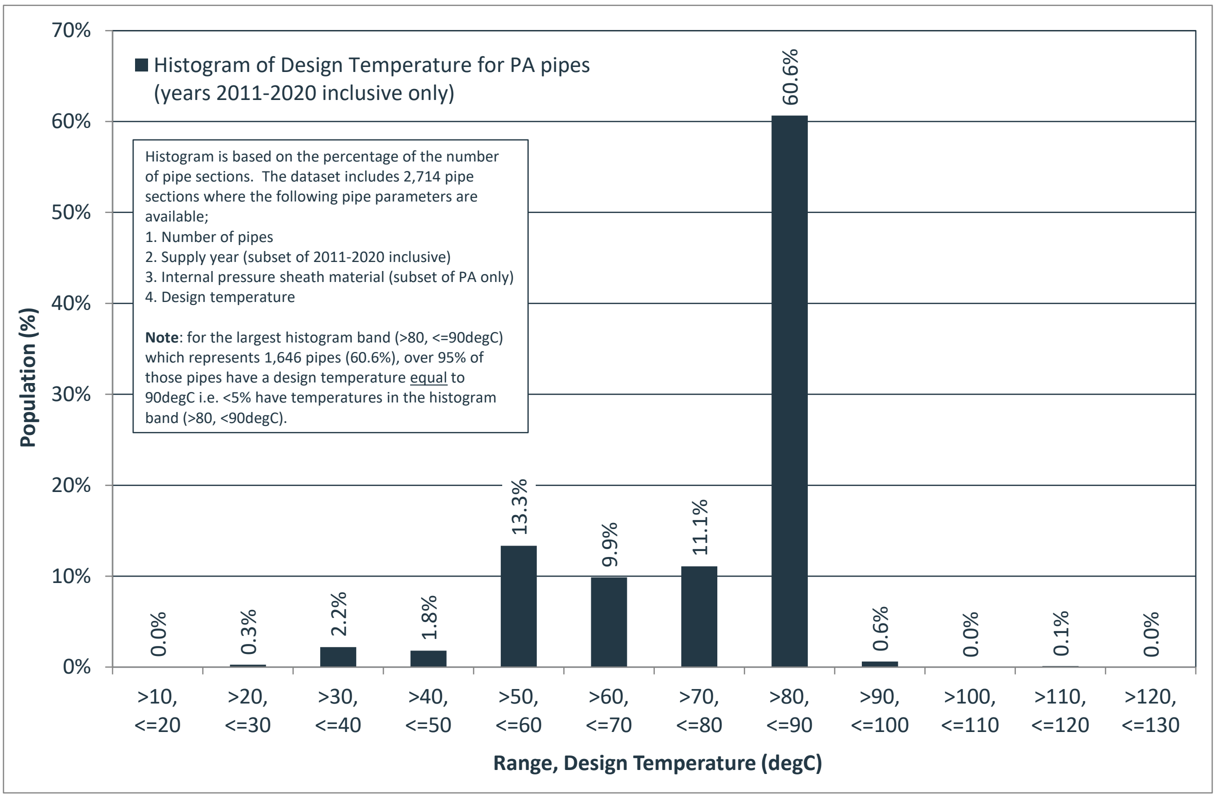


Figure 3.6 Design Temperature Histogram – PA pipes only, last 10years only

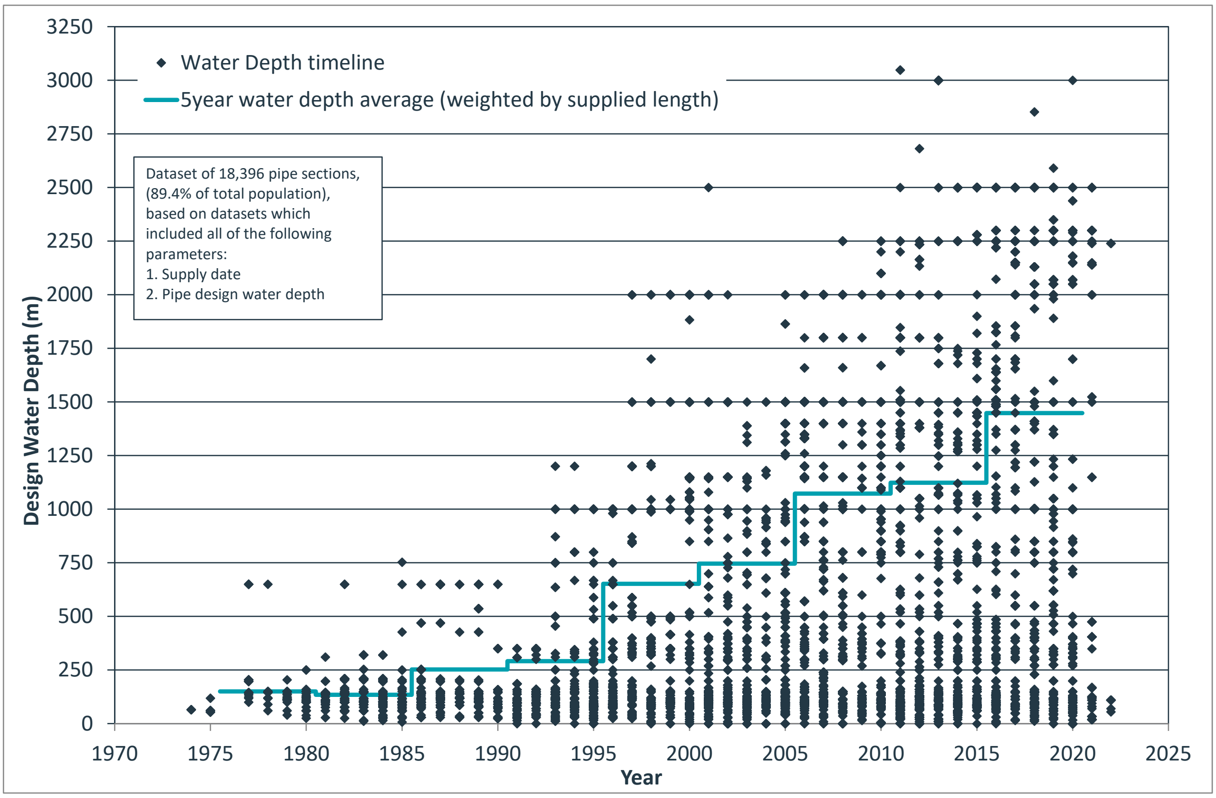


Figure 3.7 Design Water Depth (m) Timeline

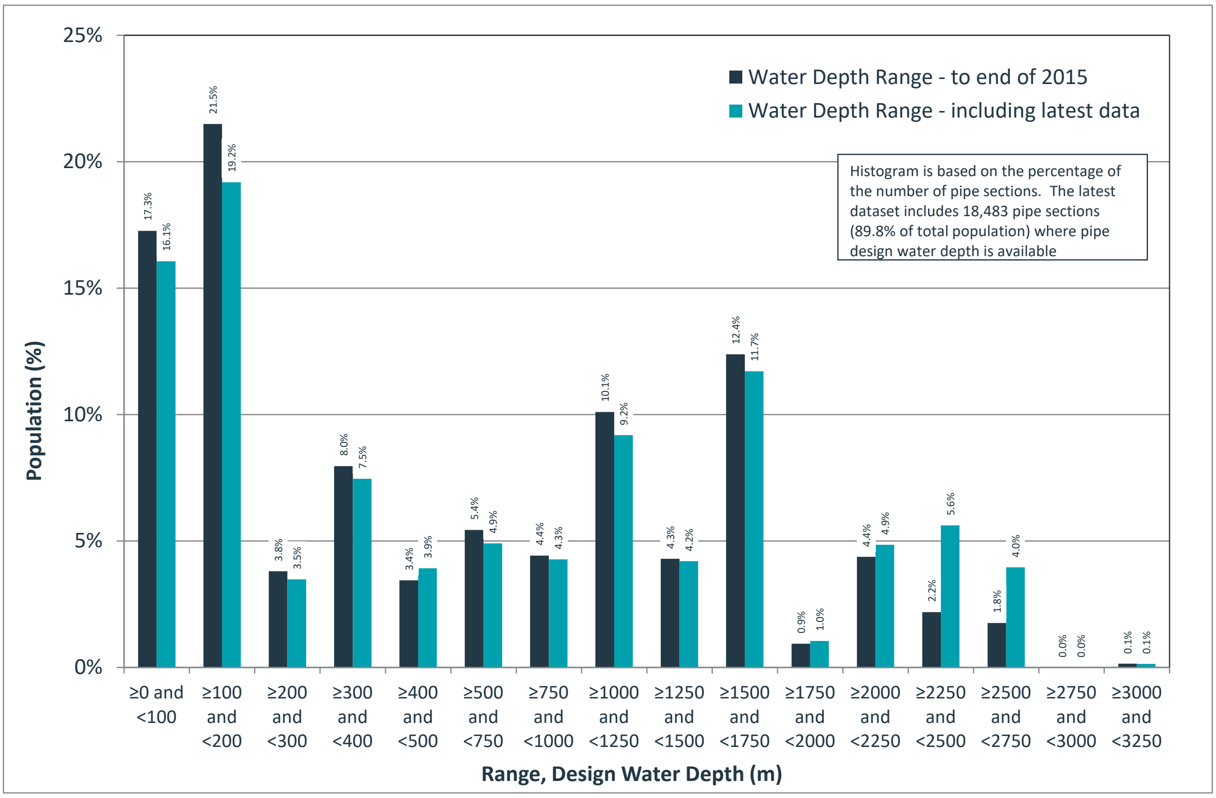


Figure 3.8 Design Water Depth (m) Histogram

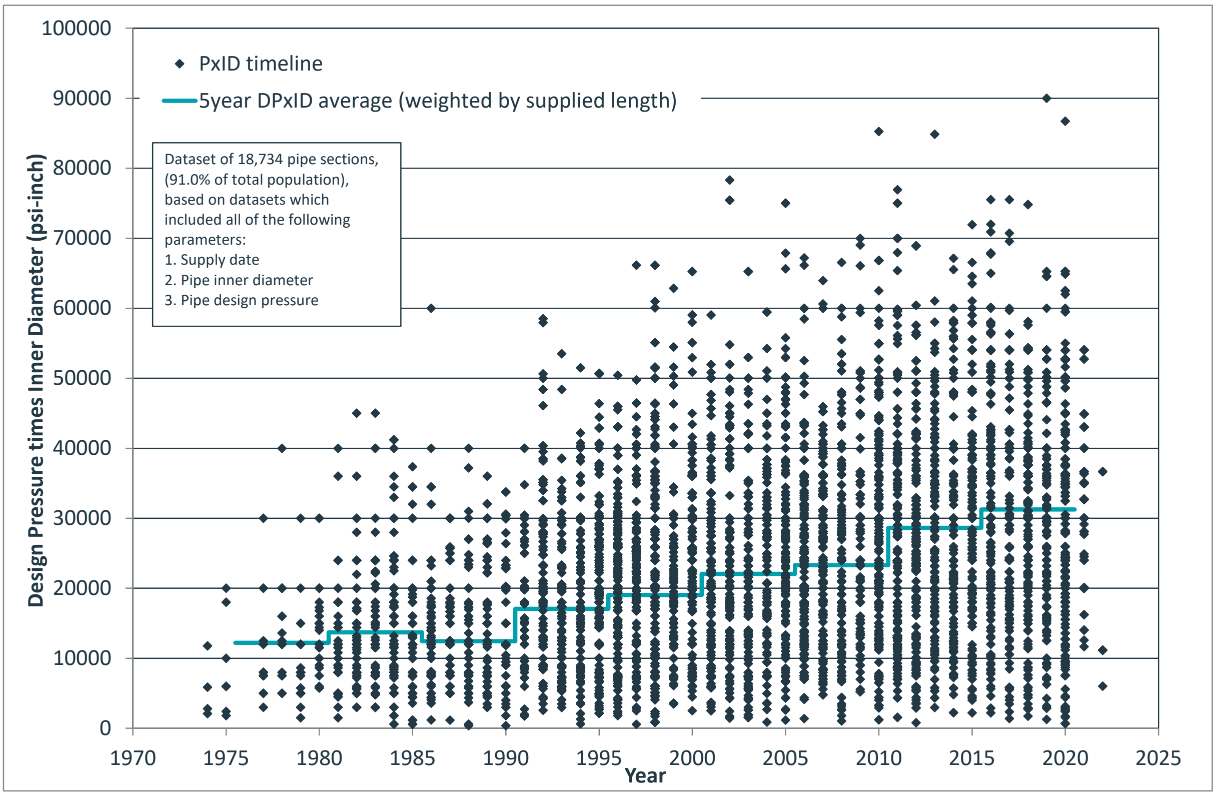


Figure 3.9 Design Pressure times Inner Diameter (psi-inch) Timeline

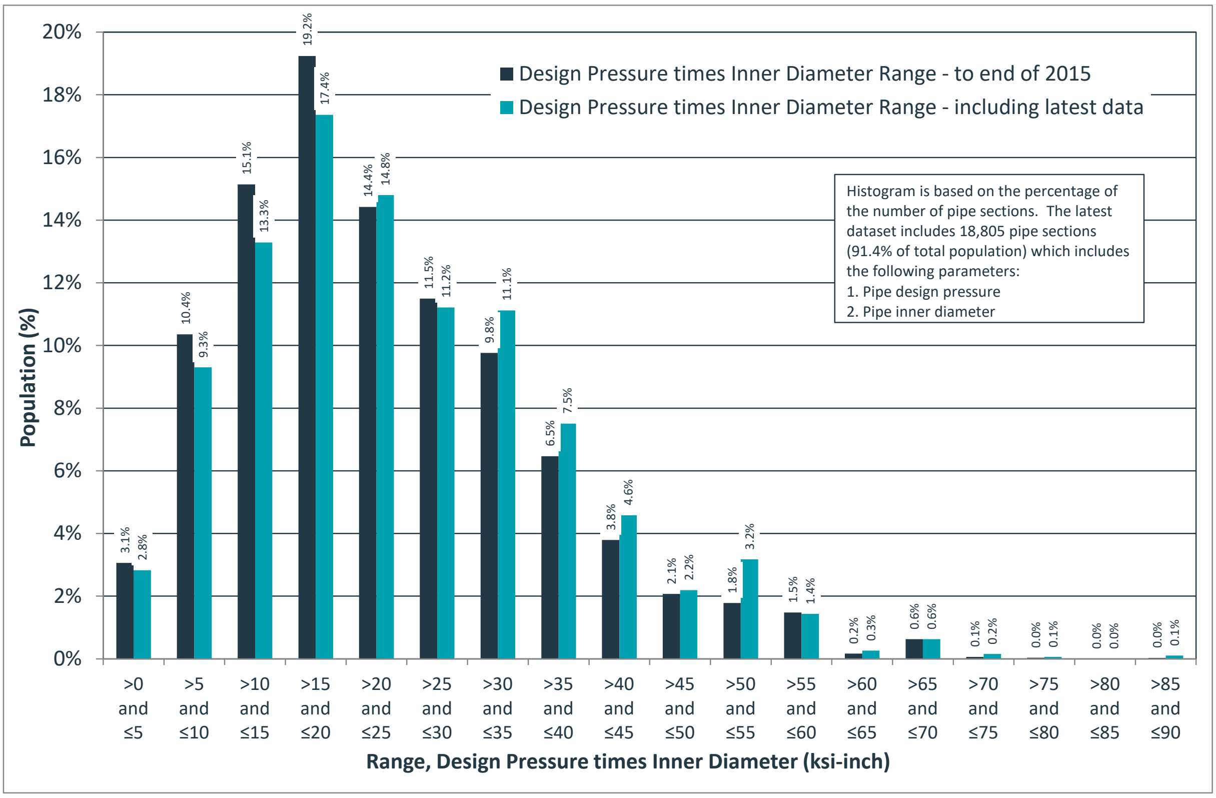


Figure 3.10 Design Pressure times Inner Diameter (ksi-inch) Histogram

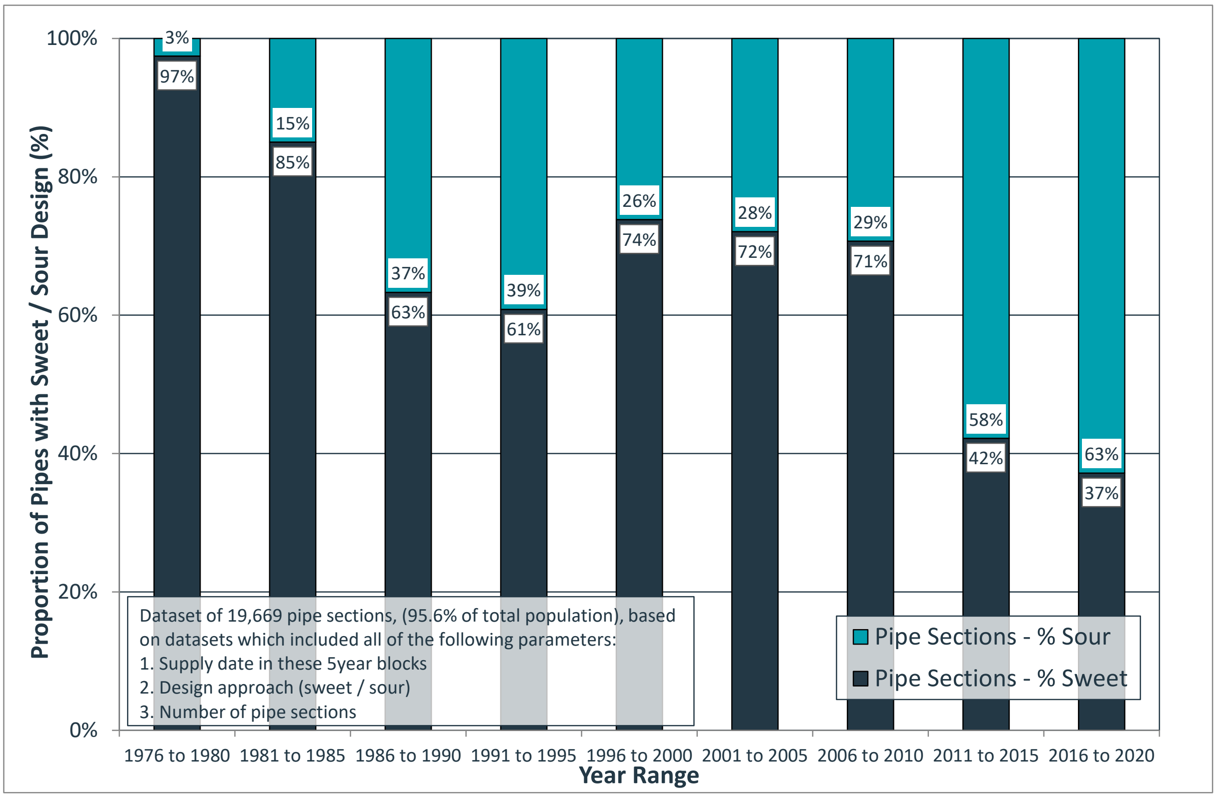


Figure 3.11 Sweet / Sour Design Applications

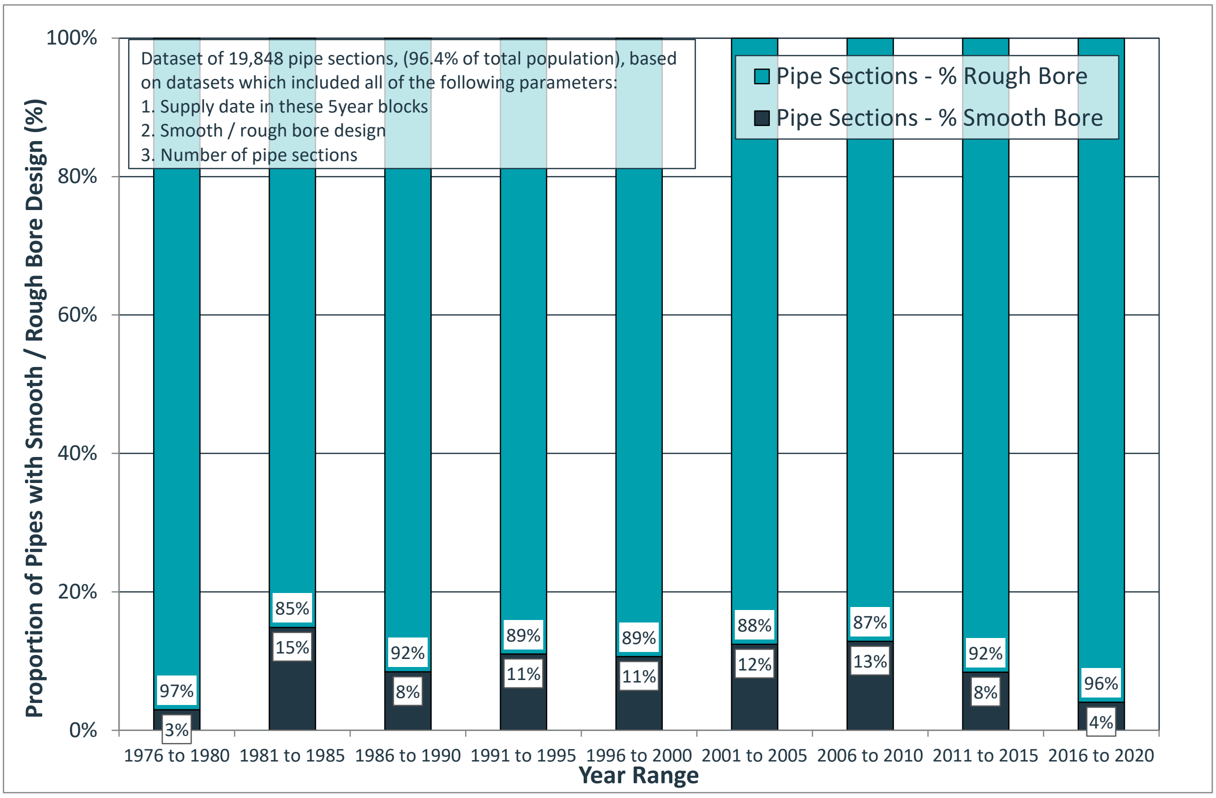


Figure 3.12 Smooth Bore / Rough Bore Applications

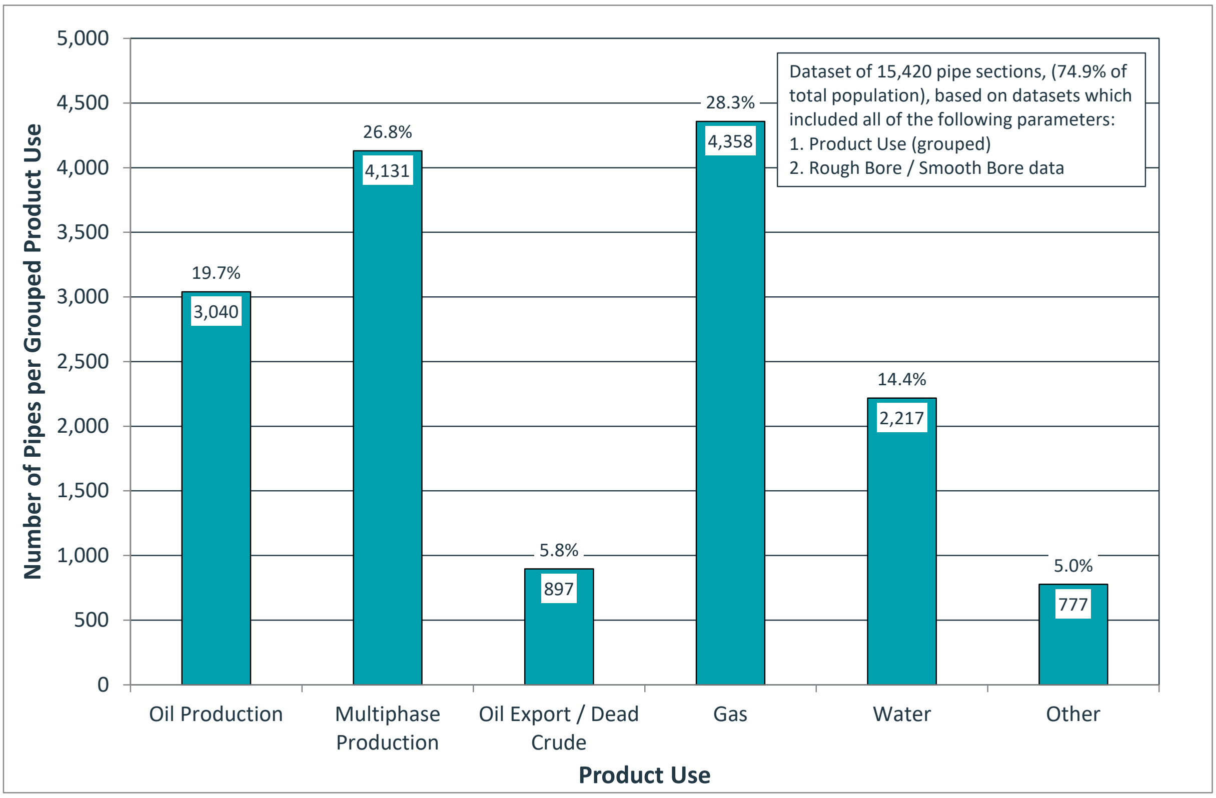


Figure 3.13 Flexible Pipe Product Use

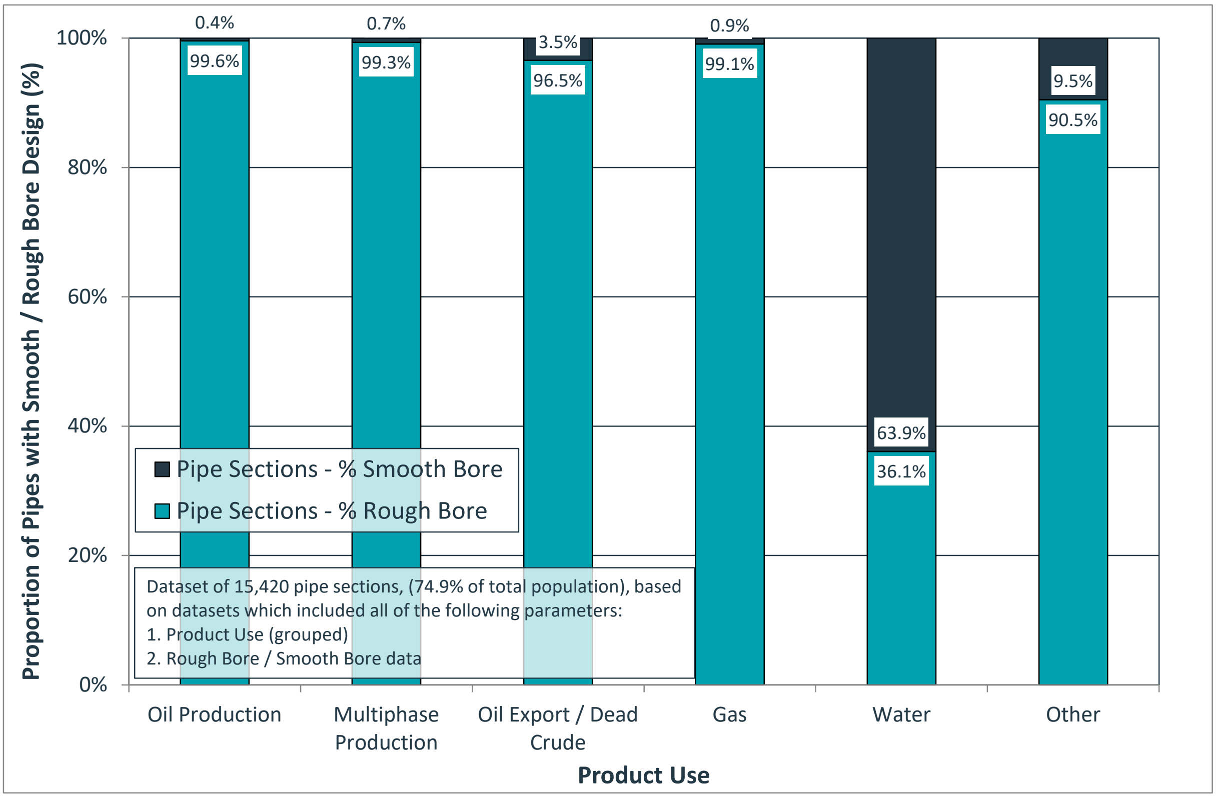


Figure 3.14 Flexible Pipe Product Use by Smooth Bore / Rough Bore

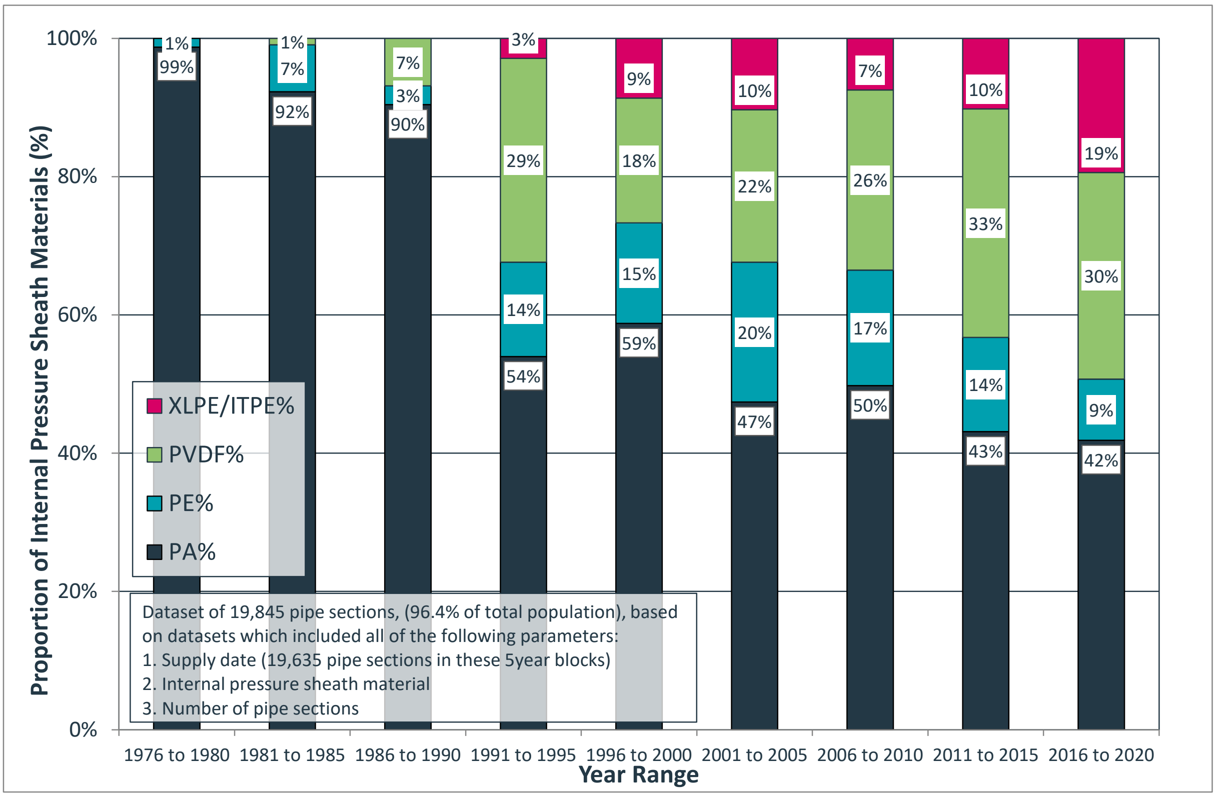


Figure 3.15 Internal Pressure Sheath Material Applications

Notes: 1. Internal Pressure Sheath materials are grouped as follows;

- PA polyamide
- PE polyethylene
- PVDF polyvinylidene difluoride
- XLPE/ITPE crosslinked polyethylene / improved temperature PE

Figure 3.16 Internal Pressure Sheath Material per Design Temperature Range (last 10 years only)

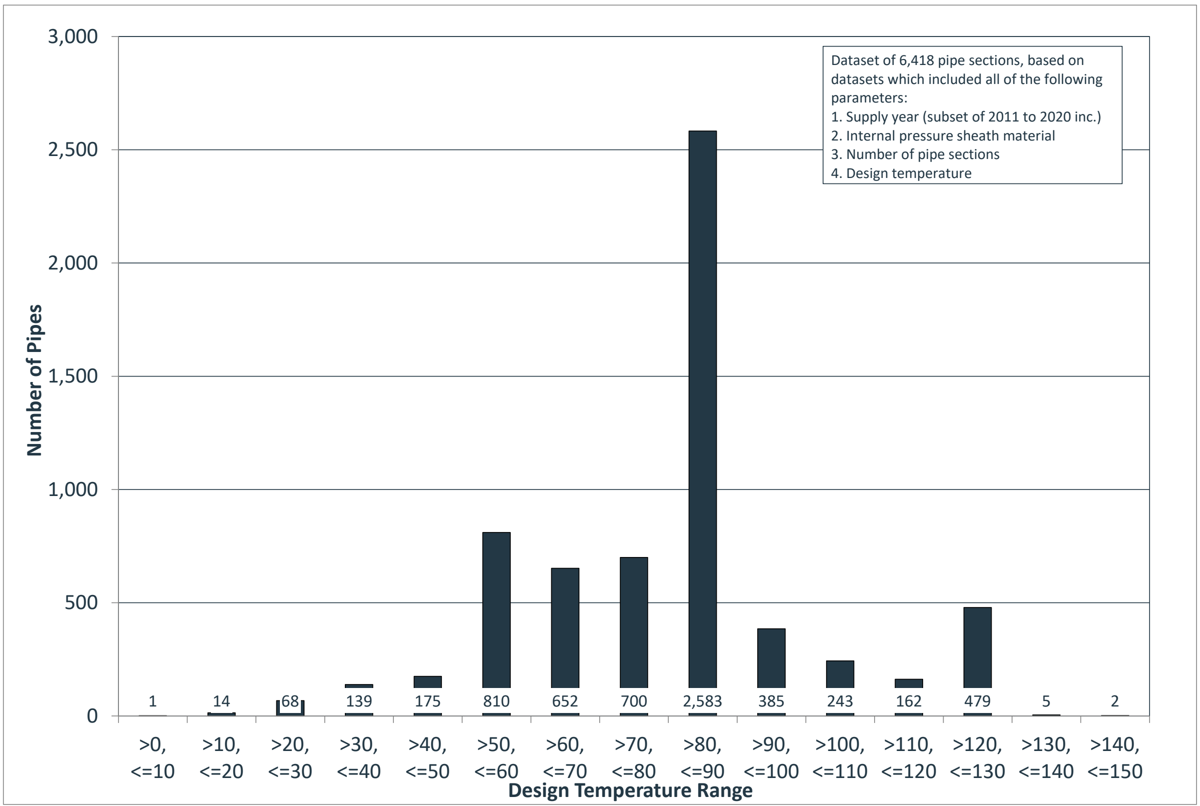


Figure 3.17 Number of Pipes per Design Temperature Range (last 10 years only)

3.5 Multi-Parameter Scatter Charts / Tables

This section of the report builds on the previous timelines and presents data in a number of different scatter charts and tables, combining multiple parameters, as noted below;

- Further to the pipe strength (DPxID product) timeline presented in Figure 3.9, the **Design Pressure vs Inner Diameter scatter** is shown in Figure 3.18. In the last 5-year period, flexible pipes have been delivered with a DPxID product of 90ksi-inch (9inch, 10ksi design pressure). When considering pipes in the higher strength ranges, the growth in application experience in the last 5-year period is significant, as shown below;

Pipes over PxID range (ksi-inch)	Counts to end of last JIP (no., and % of all)	Pipes delivered in last 5 years (% in last 5 years)	Latest Counts (no., and % of all)
50	662 (4.2%)	433 (14.3%)	1,095 (5.8%)
70	22 (0.1%)	39 (1.3%)	61 (0.3%)

  - Figure 3.19 overlays DPxID product percentiles, from 50th (22.2ksi-inch) to 99.9th (85.3ksi-inch), based on pipe section counts for all supplied pipe. Figure 3.20 shows the variation between the percentile ranges for Risers, Flowlines & Jumpers, and All pipe.
  - Figure 3.21 and Figure 3.22 show the increasing experience for higher capacity pipes, presenting the 50th and 97.5th percentile over time. Figure 3.21 is based on all data up to and including the specified years, whereas Figure 3.22 presents data within the individual 5year periods. Comparing the earliest and most recent 5year periods, the mean (50th percentile) value has increased by over a factor of three (10.00 to 30.03ksi-inch), and the upper 97.5th percentile has more than doubled (30.00 to 64.89ksi-inch).
  - The corresponding scatter tables in Figure 3.23 present counts (and percentages) of population experience in intervals of 100barg / 1inch.

- As a measure of the pipe capacity to resist external pressure / hydrostatic collapse loading, Figure 3.24 shows the **Design Water Depth vs Inner Diameter scatter** diagram. Note that for the large diameter lines (>18inch diameter) which represent mid-depth offloading lines, the design water depths have been adjusted / corrected from the field development water depths, and hence are given for information only here. These are highlighted (shaded) in the bottom right corner of the figure.

- Figure 3.25 shows the **Design Pressure vs Design Temperature scatter** diagram, with the corresponding scatter tables in Figure 3.26 presenting counts (and percentages) of population experience. Note that the intervals in the scatter tables are 5°C throughout, although for pressure, an interval of 100barg is used for most regions and reduced to 50barg in the most densely populated areas.

- Combined **Design Pressure vs Inner Diameter vs Design Water Depth scatter** tables are presented in Figure 3.27 (pipe counts) and Figure 3.28 (corresponding percentages) for all pipe. Note again that the intervals are adapted based on population densities;
  - Water depths 100m up to 500m, then 250m up to 2500m, then 500m intervals above 2500m.
  - Design pressure 2ksi up to 8ksi, then 4ksi above 8ksi.
  - Inner Diameter typically 2.5inch intervals, reduced to 1inch for most densely populated areas.

  Figure 3.29 and Figure 3.30 show the equivalent pipe counts for the separate Risers and Flowline & Jumper datasets correspondingly.

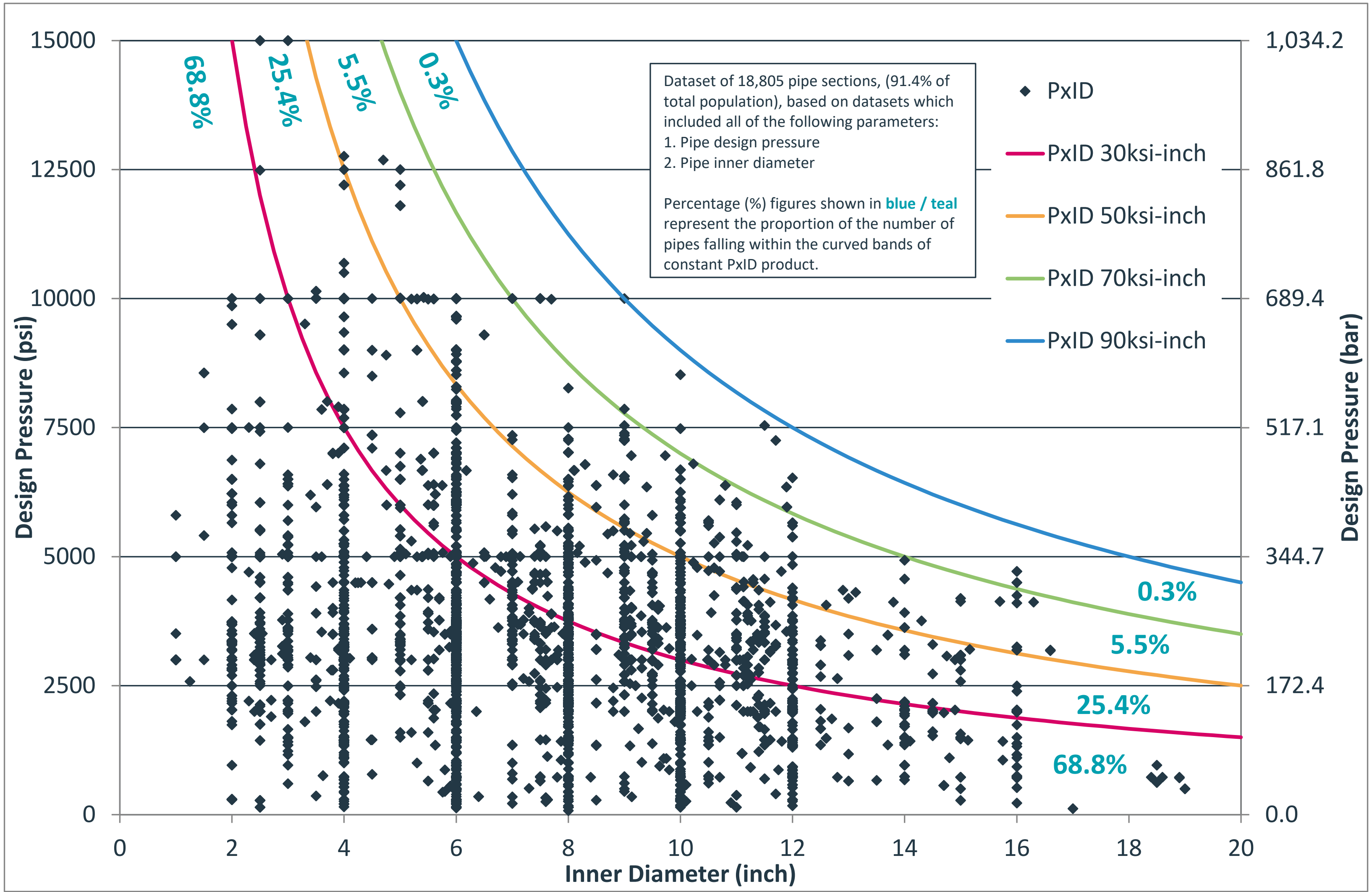


Figure 3.18 Design Pressure vs Inner Diameter Scatter (all pipe)

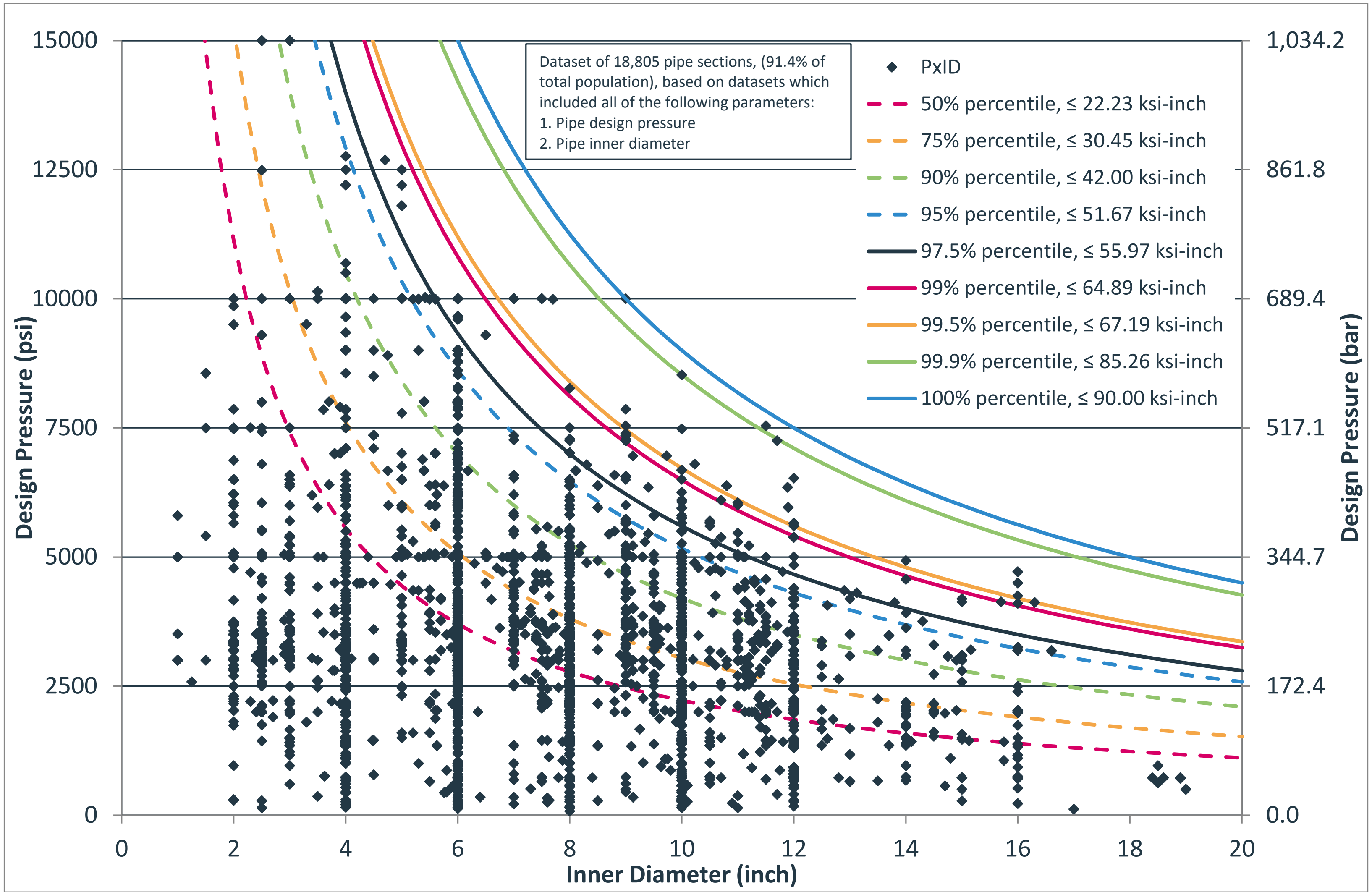


Figure 3.19 Design Pressure vs Inner Diameter Scatter, and percentile curves (all pipe)

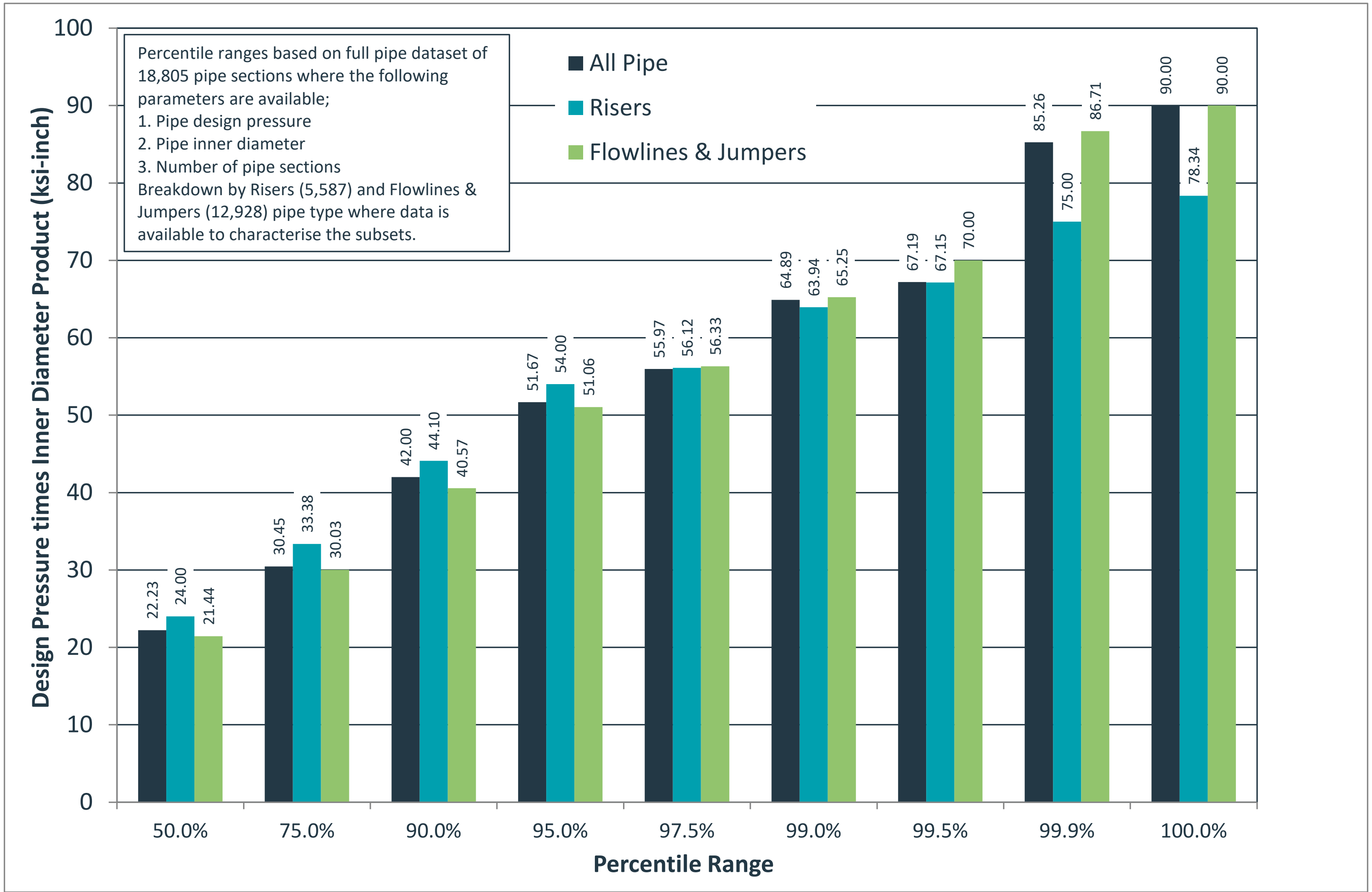


Figure 3.20 DPxID Product Percentile Values (All Pipe, Risers, Flowlines & Jumpers)

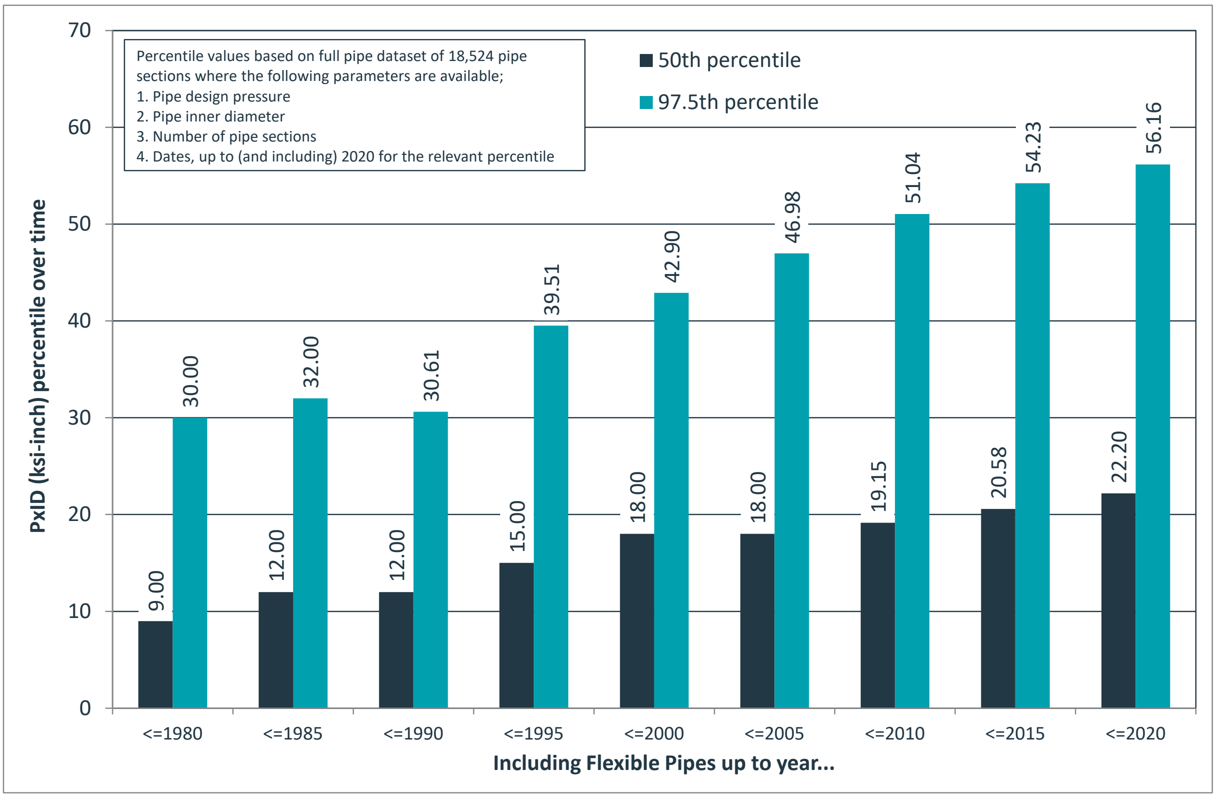


Figure 3.21 DPxID Product 50th and 97.5th Percentile Values over time (up to specified year)

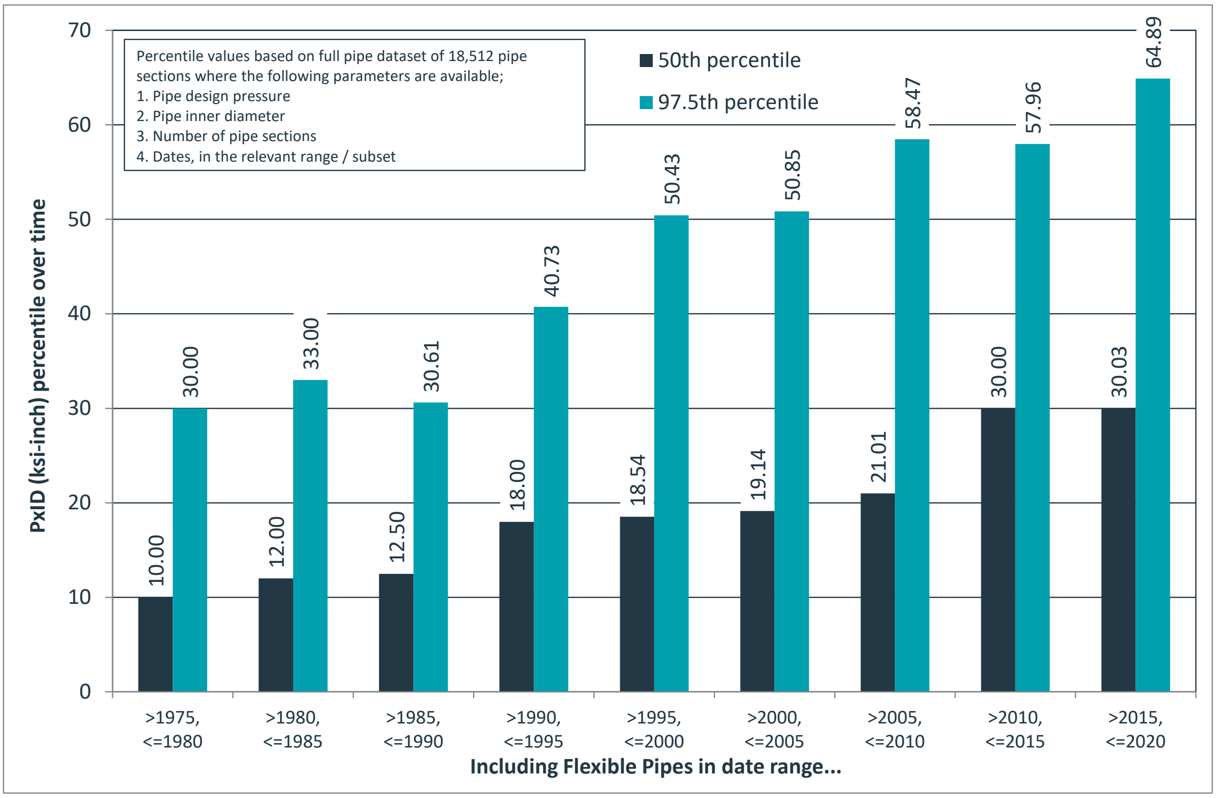


Figure 3.22 DPxID Product 50th and 97.5th Percentile Values over time (per 5year block)

Design Pressure Range (barg)	Pipe ID (inch)																				Sums by Design Pressure
	> 0 ≤ 1	> 1 ≤ 2	> 2 ≤ 3	> 3 ≤ 4	> 4 ≤ 5	> 5 ≤ 6	> 6 ≤ 7	> 7 ≤ 8	> 8 ≤ 9	> 9 ≤ 10	> 10 ≤ 11	> 11 ≤ 12	> 12 ≤ 13	> 13 ≤ 14	> 14 ≤ 15	> 15 ≤ 16	> 16 ≤ 17	> 17 ≤ 18	> 18 ≤ 19	> 19 ≤ 20	
> 1000 and ≤ 1100 barg			15																		**15**
> 900 and ≤ 1000 barg																					
> 800 and ≤ 900 barg			1	9	8																**18**
> 700 and ≤ 800 barg				13																	**13**
> 600 and ≤ 700 barg		55	74	47	17	445	16	11	2												**667**
> 500 and ≤ 600 barg		31	19	28	16	187	4	24	23	9		13									**354**
> 400 and ≤ 500 barg		37	22	63	56	443	11	67	75	28	21	14									**837**
> 300 and ≤ 400 barg	11	137	296	1093	111	1784	150	840	98	306	64	64		3		6					**4963**
> 200 and ≤ 300 barg	27	198	770	1498	129	2587	278	1020	174	913	79	364	11	17	37	22	11				**8135**
> 100 and ≤ 200 barg		98	202	392	19	487	15	512	59	649	70	235	32	55	33	14					**2872**
> 0 and ≤ 100 barg		12	21	161	9	149	15	128	14	124	29	142	8	22	30	41	1		25		**931**
Sums by Pipe ID	**38**	**568**	**1420**	**3304**	**365**	**6082**	**489**	**2602**	**445**	**2029**	**263**	**832**	**51**	**97**	**100**	**83**	**12**		**25**		
Sums ALL	**18805**																				

Design Pressure Range (barg)	Pipe ID (inch)																				Sums by Design Pressure
	> 0 ≤ 1	> 1 ≤ 2	> 2 ≤ 3	> 3 ≤ 4	> 4 ≤ 5	> 5 ≤ 6	> 6 ≤ 7	> 7 ≤ 8	> 8 ≤ 9	> 9 ≤ 10	> 10 ≤ 11	> 11 ≤ 12	> 12 ≤ 13	> 13 ≤ 14	> 14 ≤ 15	> 15 ≤ 16	> 16 ≤ 17	> 17 ≤ 18	> 18 ≤ 19	> 19 ≤ 20	
> 1000 and ≤ 1100 barg			0.08%																		**0.1%**
> 900 and ≤ 1000 barg																					
> 800 and ≤ 900 barg			0.01%	0.05%	0.04%																**0.1%**
> 700 and ≤ 800 barg				0.07%																	**0.1%**
> 600 and ≤ 700 barg		0.29%	0.39%	0.25%	0.09%	2.37%	0.09%	0.06%	0.01%												**3.5%**
> 500 and ≤ 600 barg		0.16%	0.10%	0.15%	0.09%	0.99%	0.02%	0.13%	0.12%	0.05%		0.07%									**1.9%**
> 400 and ≤ 500 barg		0.20%	0.12%	0.34%	0.30%	2.36%	0.06%	0.36%	0.40%	0.15%	0.11%	0.07%									**4.5%**
> 300 and ≤ 400 barg	0.06%	0.73%	1.57%	5.81%	0.59%	9.49%	0.80%	4.47%	0.52%	1.63%	0.34%	0.34%		0.02%		0.03%					**26.4%**
> 200 and ≤ 300 barg	0.14%	1.05%	4.09%	7.97%	0.69%	13.76%	1.48%	5.42%	0.93%	4.86%	0.42%	1.94%	0.06%	0.09%	0.20%	0.12%	0.06%				**43.3%**
> 100 and ≤ 200 barg		0.52%	1.07%	2.08%	0.10%	2.59%	0.08%	2.72%	0.31%	3.45%	0.37%	1.25%	0.17%	0.29%	0.18%	0.07%					**15.3%**
> 0 and ≤ 100 barg		0.06%	0.11%	0.86%	0.05%	0.79%	0.08%	0.68%	0.07%	0.66%	0.15%	0.76%	0.04%	0.12%	0.16%	0.22%	0.01%		0.13%		**5.0%**
Sums by Pipe ID	**0.2%**	**3.0%**	**7.6%**	**17.6%**	**1.9%**	**32.3%**	**2.6%**	**13.8%**	**2.4%**	**10.8%**	**1.4%**	**4.4%**	**0.3%**	**0.5%**	**0.5%**	**0.4%**	**0.1%**		**0.1%**		
Sums ALL	**100.0%**																				

Figure 3.23 Design Pressure vs Inner Diameter Counts / % Breakdown

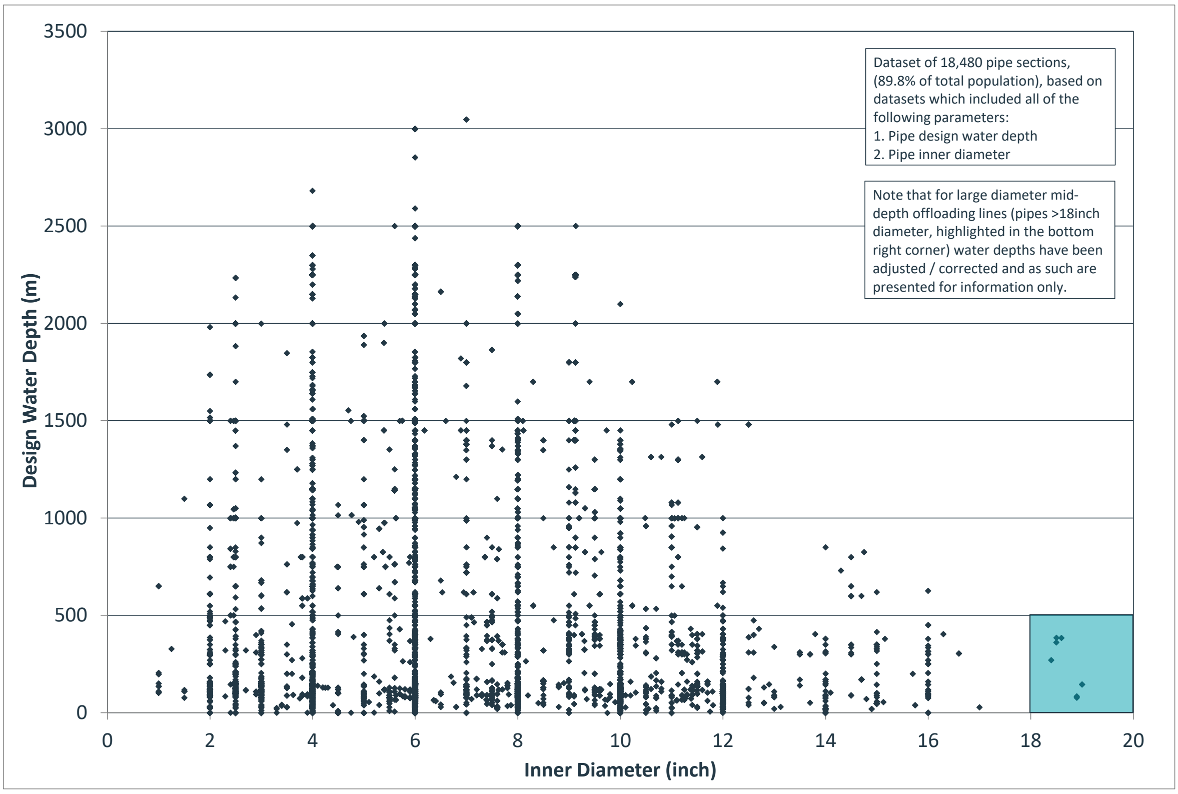


Figure 3.24 Water Depth vs Inner Diameter Scatter

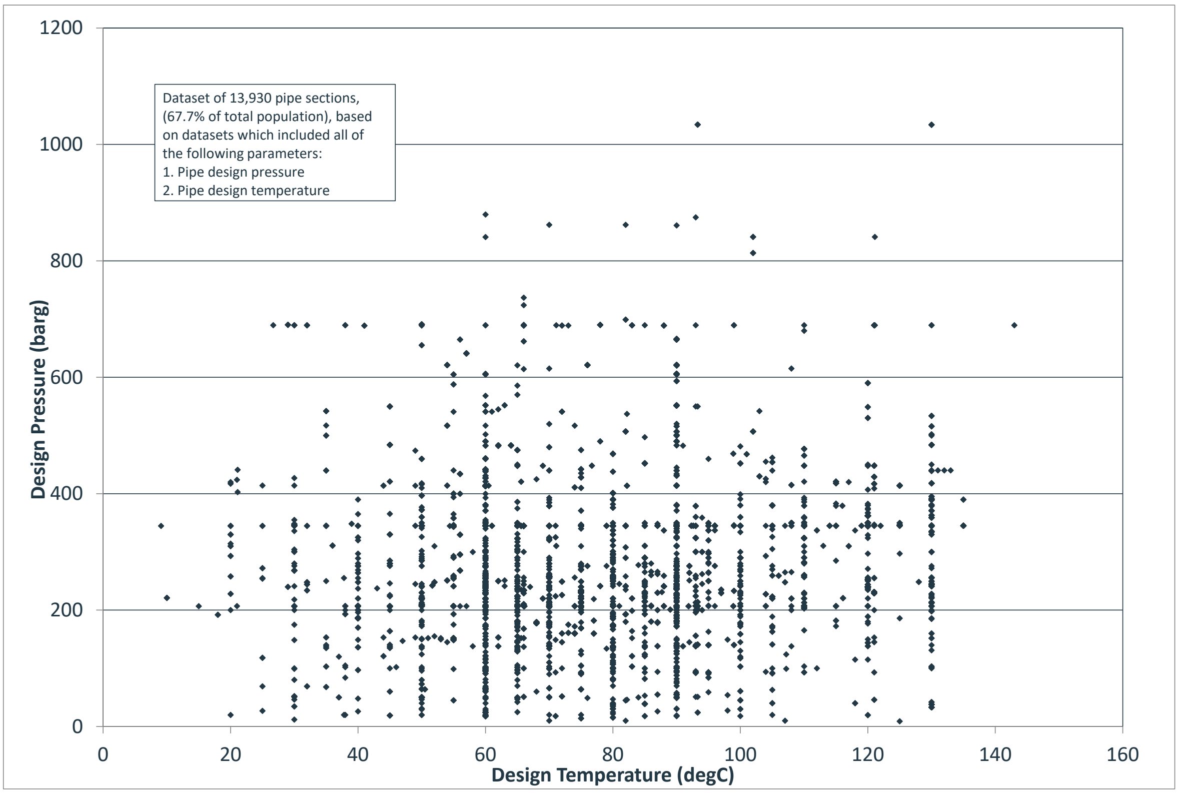


Figure 3.25 Design Pressure vs Design Temperature Scatter

Design Pressure Range (barg)	Design Temperature (degC)																													Sums by Design Pressure
	≥ 0 ≤ 5	> 5 ≤ 10	> 10 ≤ 15	> 15 ≤ 20	> 20 ≤ 25	> 25 ≤ 30	> 30 ≤ 35	> 35 ≤ 40	> 40 ≤ 45	> 45 ≤ 50	> 50 ≤ 55	> 55 ≤ 60	> 60 ≤ 65	> 65 ≤ 70	> 70 ≤ 75	> 75 ≤ 80	> 80 ≤ 85	> 85 ≤ 90	> 90 ≤ 95	> 95 ≤ 100	> 100 ≤ 105	> 105 ≤ 110	> 110 ≤ 115	> 115 ≤ 120	> 120 ≤ 125	> 125 ≤ 130	> 130 ≤ 135	> 135 ≤ 140	> 140 ≤ 145	
> 1000 and ≤ 1100 barg																			12							3				**15**
> 900 and ≤ 1000 barg																														
> 800 and ≤ 900 barg												2		1			1	1	2		10				1					**18**
> 700 and ≤ 800 barg														13																**13**
> 600 and ≤ 700 barg						35	12	2	10	12	10	30	2	13	21	19	10	318	1	11		10			13	12			2	**543**
> 500 and ≤ 600 barg							9		12		26	16	29	13	13		10	132	2		10			31		16				**319**
> 400 and ≤ 500 barg				2	10	3	9		14	16	3	130	44	29	30	32	17	167	2	24	35	71	12	8	42	29	3			**732**
> 350 and ≤ 400 barg						1		9	1	29	23	39	14	16	4	26		19	13	13	41	25	2	67		93	2			**437**
> 300 and ≤ 350 barg		1		19	10	30	12	26	8	123	28	523	142	115	76	186	90	1612	88	54	30	179	19	127	105	217	9			**3829**
> 250 and ≤ 300 barg				4	4	15		53	9	41	21	200	31	104	37	157	51	379	78	87	26	71	1	34	15	21				**1439**
> 200 and ≤ 250 barg		3	1	4	1	59	24	247	76	116	64	748	336	322	191	241	147	1315	105	88	37	55	9	116	26	101				**4432**
> 150 and ≤ 200 barg				3		2	2	90	4	13	54	95	38	315	82	96	54	90	18	34	9	10	9	7	9	22				**1056**
> 100 and ≤ 150 barg					2	1	9	8	13	24	101	42	34	34	9	67	33	41	47	17	3	4		11	2	10				**512**
> 0 and ≤ 100 barg				1	2	19	4	14	8	48	6	83	31	20	30	61	37	63	36	18	73	4	1	4	4	18				**585**
Sums by Design Temp		**4**	**1**	**33**	**29**	**165**	**81**	**449**	**155**	**422**	**336**	**1908**	**701**	**995**	**493**	**885**	**450**	**4137**	**404**	**346**	**274**	**429**	**53**	**405**	**217**	**542**	**14**		**2**	
Sums ALL	**13930**																													

Design Pressure Range (barg)	Design Temperature (degC)																													Sums by Design Pressure
	≥ 0 ≤ 5	> 5 ≤ 10	> 10 ≤ 15	> 15 ≤ 20	> 20 ≤ 25	> 25 ≤ 30	> 30 ≤ 35	> 35 ≤ 40	> 40 ≤ 45	> 45 ≤ 50	> 50 ≤ 55	> 55 ≤ 60	> 60 ≤ 65	> 65 ≤ 70	> 70 ≤ 75	> 75 ≤ 80	> 80 ≤ 85	> 85 ≤ 90	> 90 ≤ 95	> 95 ≤ 100	> 100 ≤ 105	> 105 ≤ 110	> 110 ≤ 115	> 115 ≤ 120	> 120 ≤ 125	> 125 ≤ 130	> 130 ≤ 135	> 135 ≤ 140	> 140 ≤ 145	
> 1000 and ≤ 1100 barg																			0.09%							0.02%				**0.1%**
> 900 and ≤ 1000 barg																														
> 800 and ≤ 900 barg												0.01%		0.01%			0.01%	0.01%	0.01%		0.07%				0.01%					**0.1%**
> 700 and ≤ 800 barg														0.09%																**0.1%**
> 600 and ≤ 700 barg						0.25%	0.09%	0.01%	0.07%	0.09%	0.07%	0.22%	0.01%	0.09%	0.15%	0.14%	0.07%	2.28%	0.01%	0.08%		0.07%			0.09%	0.09%			0.01%	**3.9%**
> 500 and ≤ 600 barg							0.06%		0.09%		0.19%	0.11%	0.21%	0.09%	0.09%		0.07%	0.95%	0.01%		0.07%			0.22%		0.11%				**2.3%**
> 400 and ≤ 500 barg				0.01%	0.07%	0.02%	0.06%		0.10%	0.11%	0.02%	0.93%	0.32%	0.21%	0.22%	0.23%	0.12%	1.20%	0.01%	0.17%	0.25%	0.51%	0.09%	0.06%	0.30%	0.21%	0.02%			**5.3%**
> 350 and ≤ 400 barg						0.01%		0.06%	0.01%	0.21%	0.17%	0.28%	0.10%	0.11%	0.03%	0.19%		0.14%	0.09%	0.09%	0.29%	0.18%	0.01%	0.48%		0.67%	0.01%			**3.1%**
> 300 and ≤ 350 barg		0.01%		0.14%	0.07%	0.22%	0.09%	0.19%	0.06%	0.88%	0.20%	3.75%	1.02%	0.83%	0.55%	1.34%	0.65%	11.57%	0.63%	0.39%	0.22%	1.28%	0.14%	0.91%	0.75%	1.56%	0.06%			**27.5%**
> 250 and ≤ 300 barg				0.03%	0.03%	0.11%		0.38%	0.06%	0.29%	0.15%	1.44%	0.22%	0.75%	0.27%	1.13%	0.37%	2.72%	0.56%	0.62%	0.19%	0.51%	0.01%	0.24%	0.11%	0.15%				**10.3%**
> 200 and ≤ 250 barg		0.02%	0.01%	0.03%	0.01%	0.42%	0.17%	1.77%	0.55%	0.83%	0.46%	5.37%	2.41%	2.31%	1.37%	1.73%	1.06%	9.44%	0.75%	0.63%	0.27%	0.39%	0.06%	0.83%	0.19%	0.73%				**31.8%**
> 150 and ≤ 200 barg				0.02%		0.01%	0.01%	0.65%	0.03%	0.09%	0.39%	0.68%	0.27%	2.26%	0.59%	0.69%	0.39%	**0.65%**	0.13%	0.24%	0.06%	0.07%	0.06%	0.05%	0.06%	0.16%				**7.6%**
> 100 and ≤ 150 barg					0.01%	0.01%	0.06%	0.06%	0.09%	0.17%	0.73%	0.30%	0.24%	0.24%	0.06%	0.48%	0.24%	0.29%	0.34%	0.12%	0.02%	0.03%		0.08%	0.01%	0.07%				**3.7%**
> 0 and ≤ 100 barg				0.01%	0.01%	0.14%	0.03%	0.10%	0.06%	0.34%	0.04%	0.60%	0.22%	0.14%	0.22%	0.44%	0.27%	0.45%	0.26%	0.13%	0.52%	0.03%	0.01%	0.03%	0.03%	0.13%				**4.2%**
Sums by Design Temp		**0.0%**	**0.0%**	**0.2%**	**0.2%**	**1.2%**	**0.6%**	**3.2%**	**1.1%**	**3.0%**	**2.4%**	**13.7%**	**5.0%**	**7.1%**	**3.5%**	**6.4%**	**3.2%**	**29.7%**	**2.9%**	**2.5%**	**2.0%**	**3.1%**	**0.4%**	**2.9%**	**1.6%**	**3.9%**	**0.1%**		**0.0%**	
Sums ALL	**100.0%**																													

Figure 3.26 Design Pressure vs Design Temperature Counts / % Breakdown

Design Pressure Range (ksig)	ID Range (inches)	Water Depth Range (m) ≥ 0 ≤ 100	> 100 ≤ 200	> 200 ≤ 300	> 300 ≤ 400	> 400 ≤ 500	> 500 ≤ 750	> 750 ≤ 1000	> 1000 ≤ 1250	> 1250 ≤ 1500	> 1500 ≤ 1750	> 1750 ≤ 2000	> 2000 ≤ 2250	> 2250 ≤ 2500	> 2500 ≤ 3000	> 3000 ≤ 3500	SUMS by DP
> 0 ≤ 2 ksig	≥ 1 and ≤ 2.5 inch	22	68	10				1									1572
	> 2.5 and ≤ 5 inch	206	99	12	7	2	5	2				1					
	> 5 and ≤ 7.5 inch	134	85	5	2	5	3	18	7								
	> 7.5 and ≤ 10 inch	235	139	26	10	5	10	15	2								
	> 10 and ≤ 12.5 inch	135	61	11	17	13	9										
	> 12.5 and ≤ 15 inch	52	32	5	14	5	7	3									
	> 15 and ≤ 17.5 inch	27	12	2	6												
	> 17.5 and ≤ 20 inch	8	6	3	8												
> 2 ≤ 4 ksig	1 inch		15				10										8970
	> 1 and ≤ 2 inch	87	66	5	27	44	28	12									
	> 2 and ≤ 3 inch	88	155	88	31	37	65	137	25	33		30					
	> 3 and ≤ 4 inch	342	201	72	56	86	119	272	163	177	2	100					
	> 4 and ≤ 5 inch	47	17	1	1	11	22		1	16							
	> 5 and ≤ 6 inch	363	462	74	72	139	125	322	271	502	25	252		6			
	> 6 and ≤ 7 inch	16	11	1	2	1	2	18		38		185					
	> 7 and ≤ 8 inch	331	238	52	61	78	92	102	79	180	20						
	> 8 and ≤ 9 inch	14	38	12	49	16	6	16	22	23		15					
	> 9 and ≤ 10 inch	200	140	53	276	112	64	74	82	148	3	16	73				
	> 10 and ≤ 11 inch	36	17	2	13	14	5	34	3	8							
	> 11 and ≤ 12.5 inch	144	88	42	59	53	12	31		40							
	> 12.5 and ≤ 15 inch	42	10	7	26		2	3									
	> 15 and ≤ 17.5 inch	2		5	11												
	> 17.5 and ≤ 20 inch																
> 4 ≤ 6 ksig	1 inch																5681
	> 1 and ≤ 2 inch	9	43	2	9			1	42	8	11						
	> 2 and ≤ 3 inch	61	138	18	23	1	16	10	1	14		6					
	> 3 and ≤ 4 inch	124	152	14	14	14	18	14	9	285	90	38	220	108			
	> 4 and ≤ 5 inch	54	33		9		24	3	6	3	8	4					
	> 5 and ≤ 6 inch	221	251	14	109	27	40	19	37	472	135	78	305	357	18		
	> 6 and ≤ 7 inch	37	33	3	8		14	6	5	37	14	13					
	> 7 and ≤ 8 inch	51	88	13	48	11	29	63	49	307	6	6	138	142			
	> 8 and ≤ 9 inch	15	16	9	54	10	7	7									
	> 9 and ≤ 10 inch	74	94	4	96	18	12	29	34	46		14	47	12			
	> 10 and ≤ 11 inch	1	12		17	4	16	6		8	4						
	> 11 and ≤ 12.5 inch	20	21	28	16	9		8		10							
	> 12.5 and ≤ 15 inch	4	3		5	1											
	> 15 and ≤ 17.5 inch		8	6		12	3										
	> 17.5 and ≤ 20 inch																
> 6 ≤ 8 ksig	≥ 1 and ≤ 2.5 inch	14	13	11	4	2	3		14	13	1						932
	> 2.5 and ≤ 5 inch	45	44		3	6	25	14	9	4	2	2					
	> 5 and ≤ 7.5 inch	43	56	1	71		9	37	28	71	6	5	100	72	2		
	> 7.5 and ≤ 10 inch	25	54	4	46	3	2	1		22	5						
	> 10 and ≤ 12.5 inch	3	4	10					1	13	9						
	> 12.5 and ≤ 15 inch																
	> 15 and ≤ 17.5 inch																
	> 17.5 and ≤ 20 inch																
> 8 ≤ 12 ksig	≥ 1 and ≤ 2.5 inch	2	29								35	18	5				791
	> 2.5 and ≤ 5 inch	17	26	3	4		57	24	3	1		1					
	> 5 and ≤ 7.5 inch	1	7		3	16	24	16	5	51		6	192	208	3	4	
	> 7.5 and ≤ 10 inch			21			2			2			5				
	> 10 and ≤ 12.5 inch																
	> 12.5 and ≤ 15 inch																
	> 15 and ≤ 17.5 inch																
	> 17.5 and ≤ 20 inch																
> 12 ≤ 16 ksig	≥ 1 and ≤ 2.5 inch								12				1				29
	> 2.5 and ≤ 5 inch	3		1				1		8	2				1		
	> 5 and ≤ 7.5 inch																
	> 7.5 and ≤ 10 inch																
	> 10 and ≤ 12.5 inch																
	> 12.5 and ≤ 15 inch																
	> 15 and ≤ 17.5 inch																
	> 17.5 and ≤ 20 inch																
SUMS	by WD	3355	3085	650	1287	755	887	1319	910	2540	378	790	1086	905	24	4	
	ALL	17975															

Figure 3.27 Design Pressure vs Inner Diameter vs Water Depth Combined Counts, All pipe

Design Pressure Range (ksig)	ID Range (inches)	Water Depth Range (m)															SUMS
		≥ 0 ≤ 100	> 100 ≤ 200	> 200 ≤ 300	> 300 ≤ 400	> 400 ≤ 500	> 500 ≤ 750	> 750 ≤ 1000	> 1000 ≤ 1250	> 1250 ≤ 1500	> 1500 ≤ 1750	> 1750 ≤ 2000	> 2000 ≤ 2250	> 2250 ≤ 2500	> 2500 ≤ 3000	> 3000 ≤ 3500	by DP
> 0 ≤ 2 ksig	≥ 1 and ≤ 2.5 inch	0.12%	0.38%	0.06%				0.01%									8.7%
	> 2.5 and ≤ 5 inch	1.15%	0.55%	0.07%	0.04%	0.01%	0.03%	0.01%				0.01%					
	> 5 and ≤ 7.5 inch	0.75%	0.47%	0.03%	0.01%	0.03%	0.02%	0.10%	0.04%								
	> 7.5 and ≤ 10 inch	1.31%	0.77%	0.14%	0.06%	0.03%	0.06%	0.08%	0.01%								
	> 10 and ≤ 12.5 inch	0.75%	0.34%	0.06%	0.09%	0.07%	0.05%										
	> 12.5 and ≤ 15 inch	0.29%	0.18%	0.03%	0.08%	0.03%	0.04%	0.02%									
	> 15 and ≤ 17.5 inch	0.15%	0.07%	0.01%	0.03%												
	> 17.5 and ≤ 20 inch	0.04%	0.03%	0.02%	0.04%												
> 2 ≤ 4 ksig	1 inch		0.08%				0.06%										49.9%
	> 1 and ≤ 2 inch	0.48%	0.37%	0.03%	0.15%	0.24%	0.16%	0.07%									
	> 2 and ≤ 3 inch	0.49%	0.86%	0.49%	0.17%	0.21%	0.36%	0.76%	0.14%	0.18%		0.17%					
	> 3 and ≤ 4 inch	1.90%	1.12%	0.40%	0.31%	0.48%	0.66%	1.51%	0.91%	0.98%	0.01%	0.56%					
	> 4 and ≤ 5 inch	0.26%	0.09%	0.01%	0.01%	0.06%	0.12%		0.01%	0.09%							
	> 5 and ≤ 6 inch	2.02%	2.57%	0.41%	0.40%	0.77%	0.70%	1.79%	1.51%	2.79%	0.14%	1.40%		0.03%			
	> 6 and ≤ 7 inch	0.09%	0.06%	0.01%	0.01%	0.01%	0.01%	0.10%		0.21%		1.03%					
	> 7 and ≤ 8 inch	1.84%	1.32%	0.29%	0.34%	0.43%	0.51%	0.57%	0.44%	1.00%	0.11%						
	> 8 and ≤ 9 inch	0.08%	0.21%	0.07%	0.27%	0.09%	0.03%	0.09%	0.12%	0.13%		0.08%					
	> 9 and ≤ 10 inch	1.11%	0.78%	0.29%	1.54%	0.62%	0.36%	0.41%	0.46%	0.82%	0.02%	0.09%	0.41%				
	> 10 and ≤ 11 inch	0.20%	0.09%	0.01%	0.07%	0.08%	0.03%	0.19%	0.02%	0.04%							
	> 11 and ≤ 12.5 inch	0.80%	0.49%	0.23%	0.33%	0.29%	0.07%	0.17%		0.22%							
	> 12.5 and ≤ 15 inch	0.23%	0.06%	0.04%	0.14%		0.01%	0.02%									
	> 15 and ≤ 17.5 inch	0.01%		0.03%	0.06%												
	> 17.5 and ≤ 20 inch																
> 4 ≤ 6 ksig	1 inch																31.6%
	> 1 and ≤ 2 inch	0.05%	0.24%	0.01%	0.05%			0.01%	0.23%	0.04%	0.06%						
	> 2 and ≤ 3 inch	0.34%	0.77%	0.10%	0.13%	0.01%	0.09%	0.06%	0.01%	0.08%		0.03%					
	> 3 and ≤ 4 inch	0.69%	0.85%	0.08%	0.08%	0.08%	0.10%	0.08%	0.05%	1.59%	0.50%	0.21%	1.22%	0.60%			
	> 4 and ≤ 5 inch	0.30%	0.18%		0.05%		0.13%	0.02%	0.03%	0.02%	0.04%	0.02%					
	> 5 and ≤ 6 inch	1.23%	1.40%	0.08%	0.61%	0.15%	0.22%	0.11%	0.21%	2.63%	0.75%	0.43%	1.70%	1.99%	0.10%		
	> 6 and ≤ 7 inch	0.21%	0.18%	0.02%	0.04%		0.08%	0.03%	0.03%	0.21%	0.08%	0.07%					
	> 7 and ≤ 8 inch	0.28%	0.49%	0.07%	0.27%	0.06%	0.16%	0.35%	0.27%	1.71%	0.03%	0.03%	0.77%	0.79%			
	> 8 and ≤ 9 inch	0.08%	0.09%	0.05%	0.30%	0.06%	0.04%	0.04%									
	> 9 and ≤ 10 inch	0.41%	0.52%	0.02%	0.53%	0.10%	0.07%	0.16%	0.19%	0.26%		0.08%	0.26%	0.07%			
	> 10 and ≤ 11 inch	0.01%	0.07%		0.09%	0.02%	0.09%	0.03%		0.04%	0.02%						
	> 11 and ≤ 12.5 inch	0.11%	0.12%	0.16%	0.09%	0.05%		0.04%		0.06%							
	> 12.5 and ≤ 15 inch	0.02%	0.02%		0.03%	0.01%											
	> 15 and ≤ 17.5 inch		0.04%	0.03%		0.07%	0.02%										
	> 17.5 and ≤ 20 inch																
> 6 ≤ 8 ksig	≥ 1 and ≤ 2.5 inch	0.08%	0.07%	0.06%	0.02%	0.01%	0.02%		0.08%	0.07%	0.01%						5.2%
	> 2.5 and ≤ 5 inch	0.25%	0.24%		0.02%	0.03%	0.14%	0.08%	0.05%	0.02%	0.01%	0.01%					
	> 5 and ≤ 7.5 inch	0.24%	0.31%	0.01%	0.39%		0.05%	0.21%	0.16%	0.39%	0.03%	0.03%	0.56%	0.40%	0.01%		
	> 7.5 and ≤ 10 inch	0.14%	0.30%	0.02%	0.26%	0.02%	0.01%	0.01%		0.12%	0.03%						
	> 10 and ≤ 12.5 inch	0.02%	0.02%	0.06%					0.01%	0.07%	0.05%						
	> 12.5 and ≤ 15 inch																
	> 15 and ≤ 17.5 inch																
	> 17.5 and ≤ 20 inch																
> 8 ≤ 12 ksig	≥ 1 and ≤ 2.5 inch	0.01%	0.16%								0.19%	0.10%	0.03%				4.4%
	> 2.5 and ≤ 5 inch	0.09%	0.14%	0.02%	0.02%		0.32%	0.13%	0.02%	0.01%		0.01%					
	> 5 and ≤ 7.5 inch	0.01%	0.04%		0.02%	0.09%	0.13%	0.09%	0.03%	0.28%		0.03%	1.07%	1.16%	0.02%	0.02%	
	> 7.5 and ≤ 10 inch			0.12%			0.01%			0.01%			0.03%				
	> 10 and ≤ 12.5 inch																
	> 12.5 and ≤ 15 inch																
	> 15 and ≤ 17.5 inch																
	> 17.5 and ≤ 20 inch																
> 12 ≤ 16 ksig	≥ 1 and ≤ 2.5 inch								0.07%				0.01%				0.2%
	> 2.5 and ≤ 5 inch	0.02%		0.01%				0.01%		0.04%	0.01%				0.01%		
	> 5 and ≤ 7.5 inch																
	> 7.5 and ≤ 10 inch																
	> 10 and ≤ 12.5 inch																
	> 12.5 and ≤ 15 inch																
	> 15 and ≤ 17.5 inch																
	> 17.5 and ≤ 20 inch																
SUMS	by WD	18.7%	17.2%	3.6%	7.2%	4.2%	4.9%	7.3%	5.1%	14.1%	2.1%	4.4%	6.0%	5.0%	0.1%	0.0%	
	ALL	100.0%															

Figure 3.28 Design Pressure vs Inner Diameter vs Water Depth Combined % Breakdown, All pipe

Design Pressure Range (ksig)	ID Range (inches)	Water Depth Range (m)															SUMS
		≥ 0 ≤ 100	> 100 ≤ 200	> 200 ≤ 300	> 300 ≤ 400	> 400 ≤ 500	> 500 ≤ 750	> 750 ≤ 1000	> 1000 ≤ 1250	> 1250 ≤ 1500	> 1500 ≤ 1750	> 1750 ≤ 2000	> 2000 ≤ 2250	> 2250 ≤ 2500	> 2500 ≤ 3000	> 3000 ≤ 3500	by DP
> 0 ≤ 2 ksig	≥ 0 and ≤ 2.5 inch	10	16	2													621
	> 2.5 and ≤ 5 inch	50	29	4		1		1									
	> 5 and ≤ 7.5 inch	63	24	1	1	1	3	4									
	> 7.5 and ≤ 10 inch	103	60	9	5	1	10	7									
	> 10 and ≤ 12.5 inch	44	28	5	14		8										
	> 12.5 and ≤ 15 inch	22	22	5	6	5	7	3									
	> 15 and ≤ 17.5 inch	12	10		6												
	> 17.5 and ≤ 20 inch	2	6	3	8												
> 2 ≤ 4 ksig	1 inch		11														2387
	> 1 and ≤ 2 inch	5	15		11												
	> 2 and ≤ 3 inch	9	27	12	12		4	46	7	25							
	> 3 and ≤ 4 inch	64	55	21	13	3	27	97	75	60		2					
	> 4 and ≤ 5 inch	6	5				3		1								
	> 5 and ≤ 6 inch	60	113	3	9	7	23	70	119	184	5	23		6			
	> 6 and ≤ 7 inch	3	3		2		1	2		15		55					
	> 7 and ≤ 8 inch	83	99	18	21	20	21	41	36	52							
	> 8 and ≤ 9 inch	2	4		14	7		2	8	5		3					
	> 9 and ≤ 10 inch	46	37	10	50	28	13	32	24	52	3	7	16				
	> 10 and ≤ 11 inch	13	6		5	7	5	20	2	8							
	> 11 and ≤ 12.5 inch	33	59	4	30	18		18		29							
	> 12.5 and ≤ 15 inch	10	4	5	26		1	1									
	> 15 and ≤ 17.5 inch				10												
	> 17.5 and ≤ 20 inch																
> 4 ≤ 6 ksig	1 inch																1818
	> 1 and ≤ 2 inch	2	7		4												
	> 2 and ≤ 3 inch	3	45	1	7			5	1	2							
	> 3 and ≤ 4 inch	16	49	4	3			8	9	99	17		172	18			
	> 4 and ≤ 5 inch	7	4		5				2	1							
	> 5 and ≤ 6 inch	59	68	4	56	1	2	11	9	170	38	30	207	47			
	> 6 and ≤ 7 inch	2	3		3		3	2		6		1					
	> 7 and ≤ 8 inch	22	16	11	22	1	13	14	14	58	6	6	109	34			
	> 8 and ≤ 9 inch	3	1	7	38		1	2									
	> 9 and ≤ 10 inch	20	18	2	46	1	1	11	10	8		10	21				
	> 10 and ≤ 11 inch		1		12	2				4							
	> 11 and ≤ 12.5 inch	2	10	11	11	9											
	> 12.5 and ≤ 15 inch	3	3		3												
	> 15 and ≤ 17.5 inch					8											
	> 17.5 and ≤ 20 inch																
> 6 ≤ 8 ksig	≥ 0 and ≤ 2.5 inch									4							308
	> 2.5 and ≤ 5 inch	9	4			1	15	5									
	> 5 and ≤ 7.5 inch	3	13		60		6	20	16	21			78	2			
	> 7.5 and ≤ 10 inch	6	10		20	2				10							
	> 10 and ≤ 12.5 inch	2	1														
	> 12.5 and ≤ 15 inch																
	> 15 and ≤ 17.5 inch																
	> 17.5 and ≤ 20 inch																
> 8 ≤ 12 ksig	≥ 0 and ≤ 2.5 inch																230
	> 2.5 and ≤ 5 inch		1		4		4	9	2			1					
	> 5 and ≤ 7.5 inch		1		1		6	8		1		3	137	52			
	> 7.5 and ≤ 10 inch																
	> 10 and ≤ 12.5 inch																
	> 12.5 and ≤ 15 inch																
	> 15 and ≤ 17.5 inch																
	> 17.5 and ≤ 20 inch																
> 12 ≤ 16 ksig	≥ 0 and ≤ 2.5 inch																4
	> 2.5 and ≤ 5 inch			1						1	2						
	> 5 and ≤ 7.5 inch																
	> 7.5 and ≤ 10 inch																
	> 10 and ≤ 12.5 inch																
	> 12.5 and ≤ 15 inch																
	> 15 and ≤ 17.5 inch																
	> 17.5 and ≤ 20 inch																
SUMS	by WD	799	888	143	538	123	177	439	335	815	71	141	740	159			
	ALL	5368															

Figure 3.29 Design Pressure vs Inner Diameter vs Water Depth Combined Counts – Risers only

Notes: 1. The total count of Risers (Figure 3.29, 5368) and Flowlines & Jumpers (Figure 3.30, 12380) does not equal the total for All Pipe (Figure 3.27, 17975). The difference of 227 pipes (1.3%) relates to pipes where *pipe type (Riser / Flowline / Jumper)* is not specified in the dataset.

Design Pressure Range (ksig)	ID Range (inches)	Water Depth Range (m)															SUMS
		≥ 0 ≤ 100	> 100 ≤ 200	> 200 ≤ 300	> 300 ≤ 400	> 400 ≤ 500	> 500 ≤ 750	> 750 ≤ 1000	> 1000 ≤ 1250	> 1250 ≤ 1500	> 1500 ≤ 1750	> 1750 ≤ 2000	> 2000 ≤ 2250	> 2250 ≤ 2500	> 2500 ≤ 3000	> 3000 ≤ 3500	by DP
> 0 ≤ 2 ksig	≥ 0 and ≤ 2.5 inch	12	52	8				1									935
	> 2.5 and ≤ 5 inch	156	69	8	7	1	5										
	> 5 and ≤ 7.5 inch	71	57	4	1	4		14	6								
	> 7.5 and ≤ 10 inch	131	78	17	3	4		8	2								
	> 10 and ≤ 12.5 inch	91	29	6	3	13	1										
	> 12.5 and ≤ 15 inch	30	10		8												
	> 15 and ≤ 17.5 inch	15	2	2													
	> 17.5 and ≤ 20 inch	6															
> 2 ≤ 4 ksig	1 inch		4				10										6426
	> 1 and ≤ 2 inch	80	51	5	16	38	28	12									
	> 2 and ≤ 3 inch	73	125	76	19	37	61	88	18	8		30					
	> 3 and ≤ 4 inch	262	141	50	43	46	88	171	88	117	2	98					
	> 4 and ≤ 5 inch	41	12	1	1	5	19			16							
	> 5 and ≤ 6 inch	288	347	69	63	127	102	242	151	318	20	229					
	> 6 and ≤ 7 inch	13	8	1		1	1	16		23		130					
	> 7 and ≤ 8 inch	240	137	34	40	58	71	61	43	128	20						
	> 8 and ≤ 9 inch	11	33	12	35	9	6	14	14	16		12					
	> 9 and ≤ 10 inch	154	103	42	226	78	51	42	58	96		9	57				
	> 10 and ≤ 11 inch	23	11	2	8	1		13	1								
	> 11 and ≤ 12.5 inch	110	29	38	29	35	12	13		11							
	> 12.5 and ≤ 15 inch	32	6	2			1	2									
	> 15 and ≤ 17.5 inch	2		5	1												
	> 17.5 and ≤ 20 inch																
> 4 ≤ 6 ksig	1 inch																3818
	> 1 and ≤ 2 inch	7	35	2	5			1	42	8	11						
	> 2 and ≤ 3 inch	58	93	17	16	1	16	5		12		6					
	> 3 and ≤ 4 inch	105	103	10	11	14	18	6		186	73	38	48	90			
	> 4 and ≤ 5 inch	47	29		4		24	3	4	2	8	4					
	> 5 and ≤ 6 inch	159	166	10	52	26	38	8	28	302	97	48	98	310	18		
	> 6 and ≤ 7 inch	33	30	3	5		11	4	5	31	14	12					
	> 7 and ≤ 8 inch	29	70	2	26	10	15	49	35	249			29	108			
	> 8 and ≤ 9 inch	12	15	2	12	10	6	5									
	> 9 and ≤ 10 inch	53	67	2	50	17	11	18	24	38		4	26	12			
	> 10 and ≤ 11 inch	1	11		5	2	16	5		4	4						
	> 11 and ≤ 12.5 inch	18	11	17	5			8		10							
	> 12.5 and ≤ 15 inch	1			2	1											
	> 15 and ≤ 17.5 inch		8	6		4	3										
	> 17.5 and ≤ 20 inch																
> 6 ≤ 8 ksig	≥ 0 and ≤ 2.5 inch	14	13	11	4	2	3		14	9	1						618
	> 2.5 and ≤ 5 inch	36	40		3	5	10	9	9	4	2	2					
	> 5 and ≤ 7.5 inch	39	39	1	11		3	17	12	49	6	5	22	70	2		
	> 7.5 and ≤ 10 inch	19	44	4	26	1	2	1		12	5						
	> 10 and ≤ 12.5 inch	1	3	10					1	13	9						
	> 12.5 and ≤ 15 inch																
	> 15 and ≤ 17.5 inch																
	> 17.5 and ≤ 20 inch																
> 8 ≤ 12 ksig	≥ 0 and ≤ 2.5 inch	2	29								35	18	5				560
	> 2.5 and ≤ 5 inch	17	25	3			53	15	1	1							
	> 5 and ≤ 7.5 inch	1	6		2	16	18	8	4	50		3	55	156	3	4	
	> 7.5 and ≤ 10 inch			21			2			2			5				
	> 10 and ≤ 12.5 inch																
	> 12.5 and ≤ 15 inch																
	> 15 and ≤ 17.5 inch																
	> 17.5 and ≤ 20 inch																
> 12 ≤ 16 ksig	≥ 0 and ≤ 2.5 inch								12				1				23
	> 2.5 and ≤ 5 inch	1						1		7					1		
	> 5 and ≤ 7.5 inch																
	> 7.5 and ≤ 10 inch																
	> 10 and ≤ 12.5 inch																
	> 12.5 and ≤ 15 inch																
	> 15 and ≤ 17.5 inch																
	> 17.5 and ≤ 20 inch																
SUMS	by WD	2494	2141	503	742	566	705	860	572	1722	307	648	346	746	24	4	
	ALL	12380															

Figure 3.30 Design Pressure vs Inner Diameter vs Water Depth Combined Counts – Flowlines & Jumpers only

Notes: 1. The total count of Risers (Figure 3.29, 5368) and Flowlines & Jumpers (Figure 3.30, 12380) does not equal the total for All Pipe (Figure 3.27, 17975). The difference of 227 pipes (1.3%) relates to pipes where *pipe type (Riser / Flowline / Jumper)* is not specified in the dataset.

3.6 Population & Operational Experience

In the following Section (4.0), the experience of in-service *Damage* and *Failure* over time is presented. Corresponding incident rates are also presented, and operational experience statistics are thus required as they form the denominator of those calculations. This operational experience data is derived in this section.

3.6.1 Adjustment Factors and Pipe Age

As noted in Section 3.2, one of the limitations of utilising "supply" data is that the manufacturers often receive little feedback from the users of flexible pipe once it is delivered. As such, some corrections are made to the "as-supplied" data by applying adjustment factors based on the pipe supply age in order to estimate operational experience. These adjustment factors account for pipes which go into storage as spares in early life, and for pipes which are removed from service as a result of *Damage* / *Failure* or due to cessation of production of a field (the timelines of which vary significantly).

In the previous JIP phase (Ref. [13]) these factors were based on engineering judgement and were common to all flexible pipe types (Risers, Flowlines & Jumpers). These were peer reviewed by the JIP membership, and sensitivity analyses considering relatively large variations in the adjustment factors concluded that the effect on the different incident rate trends was low. In this iteration of the JIP, an additional dataset has been gathered from JIP member operators to define the adjustment factors using quantified data. Whilst this is a partial dataset representing 12% and 5% of the full dataset respectively (i.e. 700 Risers, and 734 Flowlines & Jumpers), it is likely to be more representative of actual operating experience.

This additional analysis has shown that, when considering all flexible pipes in combination, the previous phase approach was generally pessimistic / conservative (with the exception of a single 5year period). The "exception" period is predominantly driven by a large known population in the gathered data relating to specific riser integrity issues for pipes in the range of 15 to 20 years old. However, the newly gathered data has confirmed that the adjustment factors vary depending on pipe type i.e. Risers compared to Flowlines & Jumpers. This is not surprising given the differing loads / risks / threats associated with the two groups, but the new data allows the subsequent operational experience to be more representative.

Figure 3.31 and Figure 3.32 show the adjustment factors for Risers and Flowlines & Jumpers respectively. On each plot, the calculated factors are shown, alongside the selected / applied factors (using a lesser degree of engineering judgement). All the applied factors are within +/- 5% points of the calculated figures, with the exception of the Risers factor for pipes in the 15 to 20 year old age range as noted above.

Data relating to flexible pipe year of manufacture was available for 20,170 pipe sections within the database (98.0% of the total supplied inventory). Of those pipes, pipe type is specified for 19,554 pipe sections (96.9% of the previous subset, or 95.0% of the full supplied inventory). Figure 3.33 and Figure 3.34 (and Table 3.3) show histogram data relating to the age of these pipe groups for All Pipe, Risers (5,904 supplied sections) and Flowlines & Jumpers (13,650 supplied sections) respectively. The histogram series are based on;

1. Figure 3.33 – pipe age from the manufacture / supply date up to 2021 (based on all supplied pipe sections),
2. Figure 3.34 – adjusted pipe age, applying the adjustment factors, accounting for pipes not in service, giving;
   - an effective reduction to 3,734 operational Risers (63.2% of those ever manufactured),
   - an effective reduction to 10,544 operational Flowlines & Jumpers (77.2% of those ever manufactured).

The oldest flexible pipes in the database were supplied 47 years ago, and in relatively small numbers during the infancy of the industry. As such, flexible pipe technology is still relatively young compared to that of rigid steel pipe; some pipelines remain in operation today that are decades older than the oldest flexible pipes. Almost half (48.9%) of all flexible pipes ever manufactured were supplied in the last 15 years (since 2005), and 86.3% were manufactured in the last 30 years. A simplified average age from supply can be calculated using the data for the Figure 3.33 histogram, giving an average age of 16.4 years for Risers, and 17.5 years for Flowlines & Jumpers.

When considering the adjusted figures, which is the best estimate of the latest operational pipe inventory, 76.4% of Risers / 58.2% of Flowlines & Jumpers have less than 15 years in service, and 99.5% of Risers / 96.7% of Flowlines & Jumpers have less than 30 years service. Operational pipes over 30 years old correspond to 19 Risers / 345 Flowlines & Jumpers equivalent pipe sections (or 0.32% / 2.53% of the total number of pipe sections ever supplied for which a manufacture and supply date is available).

3.6.2 Manufactured Length

Figure 3.35 and Figure 3.36 show the total cumulative flexible pipe length, with trends presented for all flexible pipe, as well as for the two sub-groups (Risers and Flowlines & Jumpers). The data is presented on both linear (Figure 3.35) and log (Figure 3.36) scales to allow the industry trends in the early years to be illustrated, as they are masked on a linear scale due to the large supply inventories in more recent years. To the end of the 2020, over 18,000km of flexible pipe have been supplied.

3.6.3 Operational Experience

The operational experience in pipe-years is established using the parameters noted in the previous sections. Table 3.4 and Figure 3.37 present the operational experience of flexible pipes. Operational experience is calculated in 5-year intervals from 1976 to 2021 in “pipe-years”. Data is presented for both Riser and Flowline & Jumper experience, acknowledging the significantly different applications of flexible pipe i.e. dynamic vs static.

Whilst “km-years” are sometimes used as the basis for operational experience, the use of “pipe-years” is more valid for flexible pipe systems when evaluating pipe *Failure* / *Damage* rates, and is consistent with the previously applied approach, Ref. [13]. The largest contributors to flexible pipe *Damage* and *Failure* typically affect the pipe on a “per pipe basis” as opposed to a “per unit length basis” e.g. annulus flooding, ancillary equipment, carcass defects, pressure sheath defects, armour wire degradation, and remediation / repair on a per unit length basis is not normally feasible (whereas it is normally more achievable on rigid steel pipe).

Figure 3.38 presents flexible pipe operational experience for all pipes in pipe-years, including the annual cumulative figures (on both linear and log scales for clarity) and the annual year-on-year growth in experience. The year-on-year growth data also shows a 4th order polynomial fitted to the data, with the trend showing a slowing of the rate of increase as the industry matures and the adjustment factors take greater effect.

Care should be taken in the selection of “experience” figures when using this data to establish *Damage* / *Failure* rates. In particular, the application of a “pipe-years” or “km-years” value should be carefully considered, especially where a comparison is made between flexible and rigid pipe technologies which typically have different applications and unit lengths.

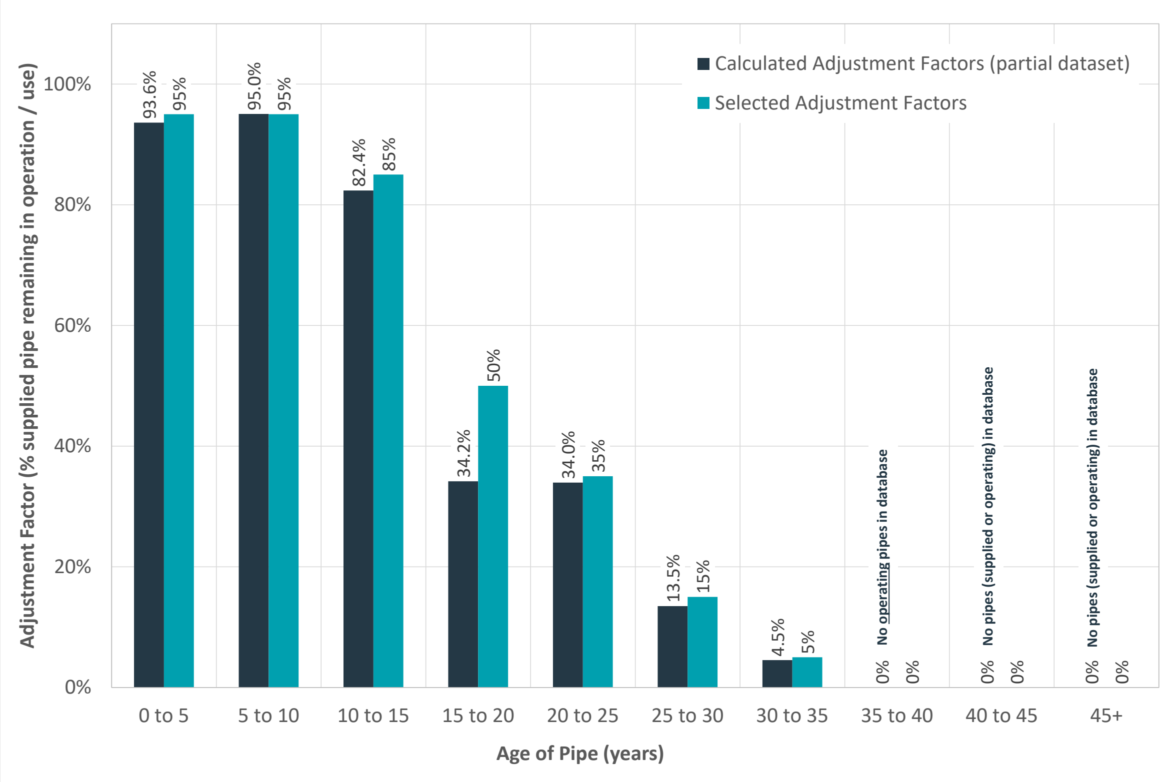


Figure 3.31 Adjustment Factors - Risers

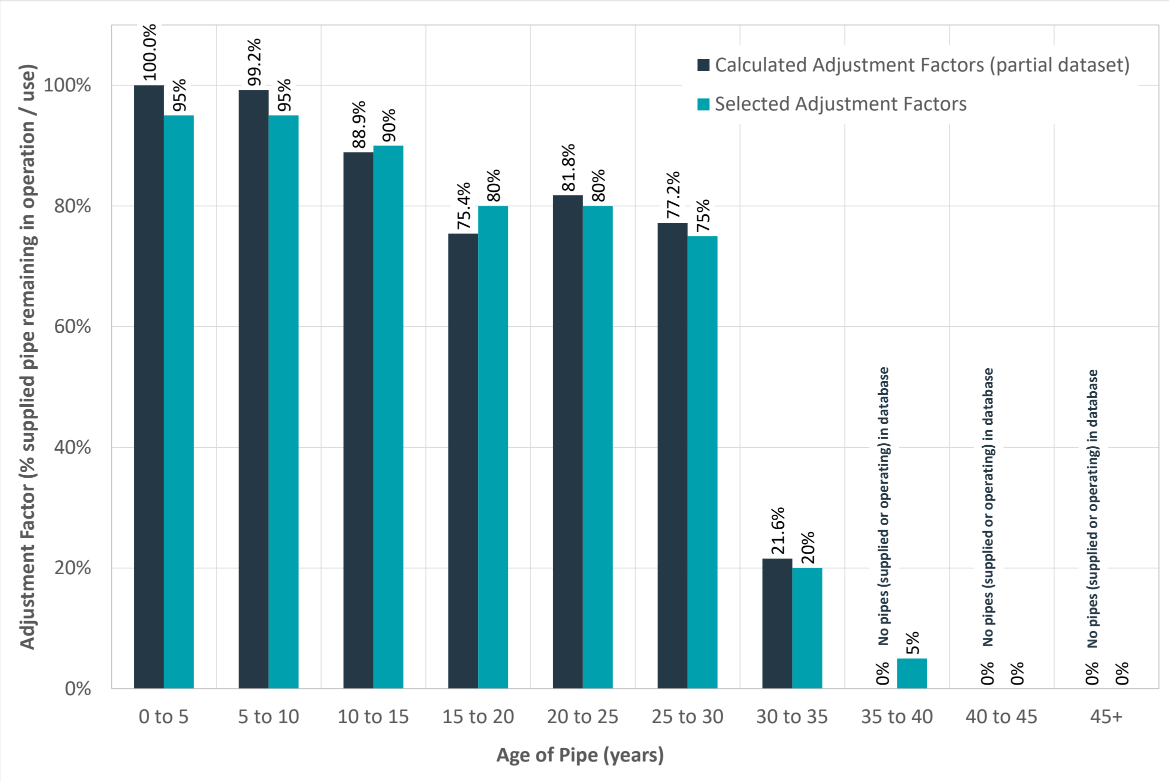


Figure 3.32 Adjustment Factors - Flowlines & Jumpers

Table 3.3 Flexible Pipe Population, Supplied Pipes vs Adjusted Age Pipes

Age Range from supply (years)	Number of Pipes						Histogram %					
	All Pipe		Risers		Flowline& Jumpers		All Pipe		Risers		Flowline& Jumpers	
	Supplied	Adjusted	Supplied	Adjusted	Supplied	Adjusted	Supplied	Adjusted	Supplied	Adjusted	Supplied	Adjusted
0 to 5	2,369	2,248	831	789	1,535	1,458	11.7%	15.7%	14.1%	21.1%	11.2%	13.8%
5 to 10	3,389	3,209	1,088	1,034	2,290	2,176	16.8%	22.5%	18.4%	27.7%	16.8%	20.6%
10 to 15	4,107	3,536	1,177	1,028	2,753	2,508	20.4%	24.8%	19.9%	27.5%	20.2%	23.8%
15 to 20	2,713	2,020	736	447	1,891	1,573	13.5%	14.1%	12.5%	12.0%	13.9%	14.9%
20 to 25	2,700	1,634	806	304	1,663	1,330	13.4%	11.4%	13.7%	8.1%	12.2%	12.6%
25 to 30	2,132	1,268	577	114	1,516	1,154	10.6%	8.9%	9.8%	3.0%	11.1%	10.9%
30 to 35	1,188	293	244	16	890	277	5.9%	2.1%	4.1%	0.4%	6.5%	2.6%
35 to 40	1,232	69	361	3	859	66	6.1%	0.5%	6.1%	0.1%	6.3%	0.6%
40 to 45	328	2	78	0	247	2	1.6%	0.0%	1.3%	0.0%	1.8%	0.0%
45 to 50	12	0	6	0	6	0	0.1%	0.0%	0.1%	0.0%	0.0%	0.0%
Totals Note1	**20,170**	**14,278**	**5,904**	**3,734**	**13,650**	**10,544**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**
Adjusted Pipes in Use	-	**70.8%**	-	**63.2%**	-	**77.2%**	-					

Notes: 1. Data is presented for as large a population that can be considered based on the limitations of the dataset i.e.
- 20,170 pipes with a specified *supply date* up to and including 2021 (98.0% of the full dataset of 20,583 pipes)
- 19,554 of those pipes (96.9%) which additionally have a specified *pipe type* (5,904 Risers and 13,650 Flowlines & Jumpers)

2. Number of adjusted pipes are calculated using Adjustment Factors defined for Risers (Figure 3.31) and Flowlines & Jumpers (Figure 3.32).

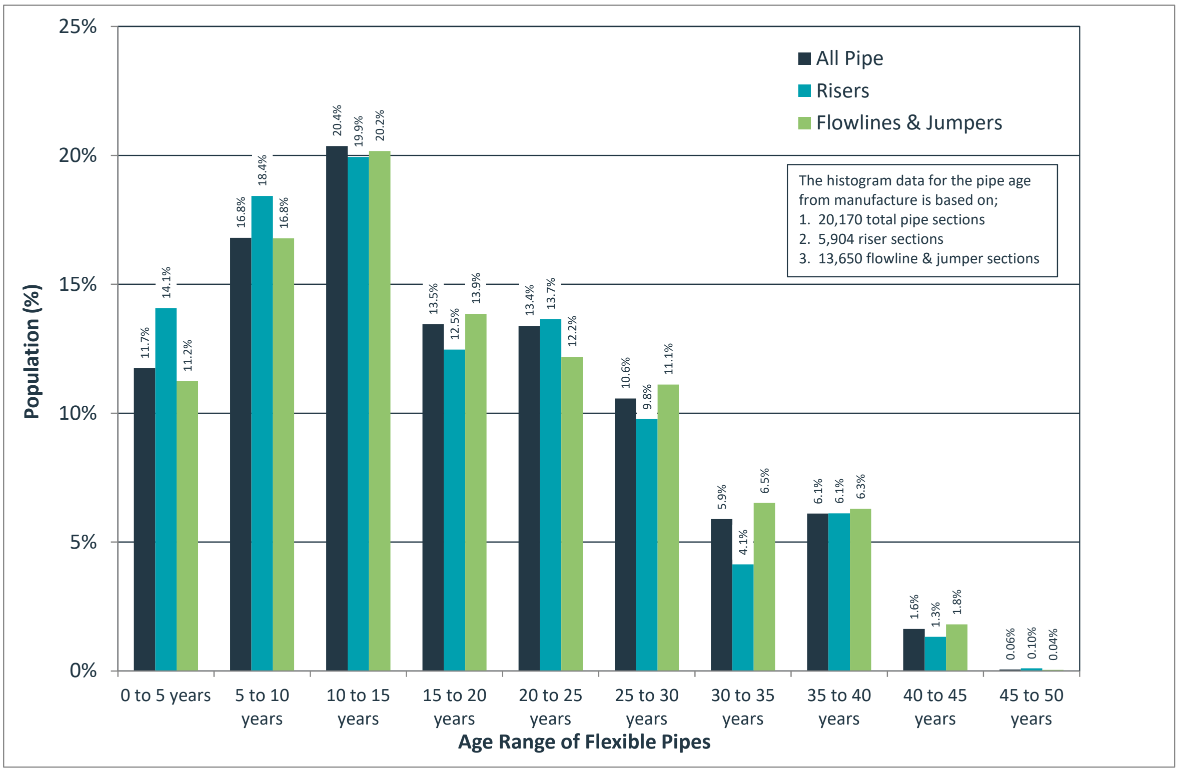


Figure 3.33 Flexible Pipe Age Histogram – Age from Manufacture to 2021

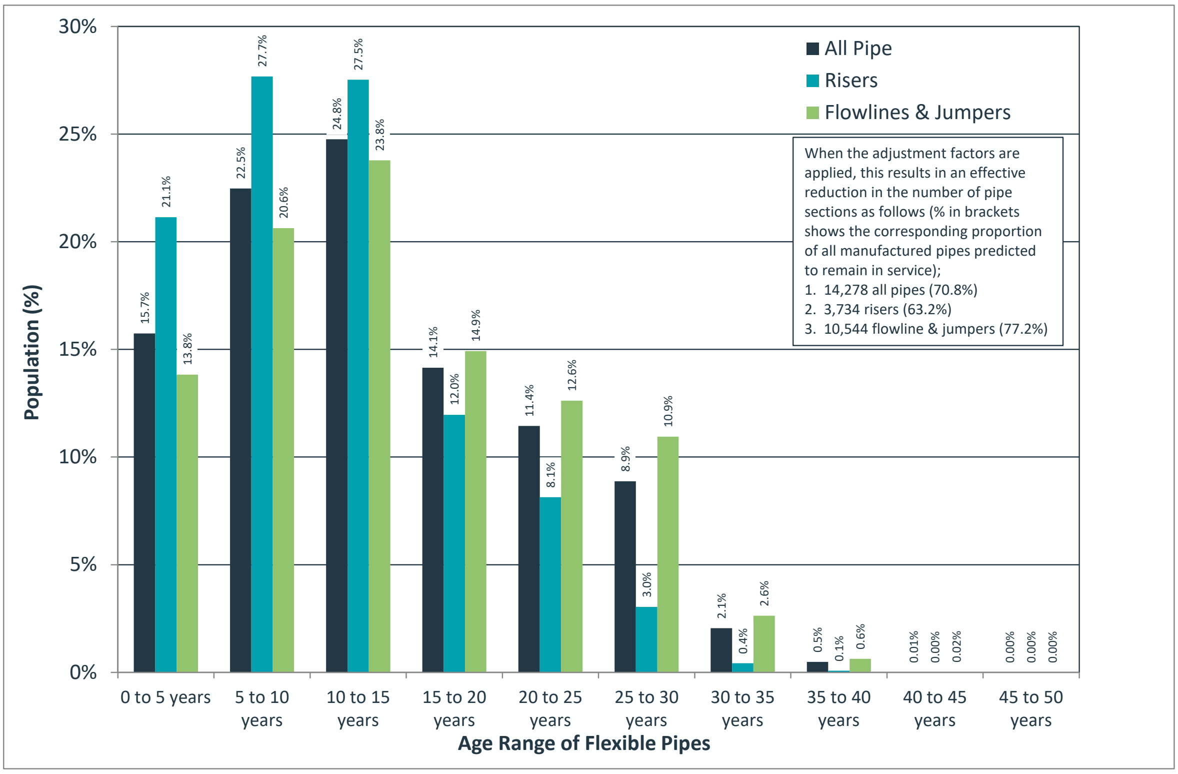


Figure 3.34 Flexible Pipe Age Histogram – Adjusted Age to 2021

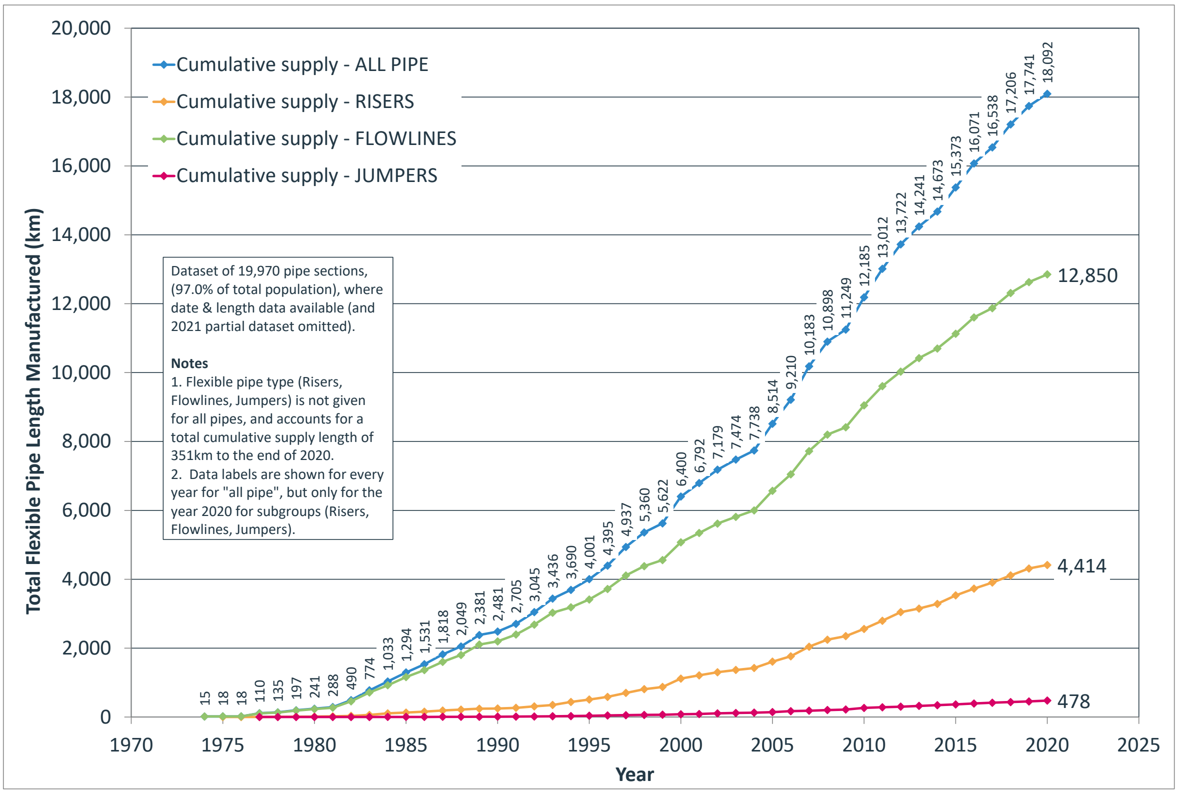


Figure 3.35 Total Cumulative Flexible Pipe Length Manufactured (linear scale)

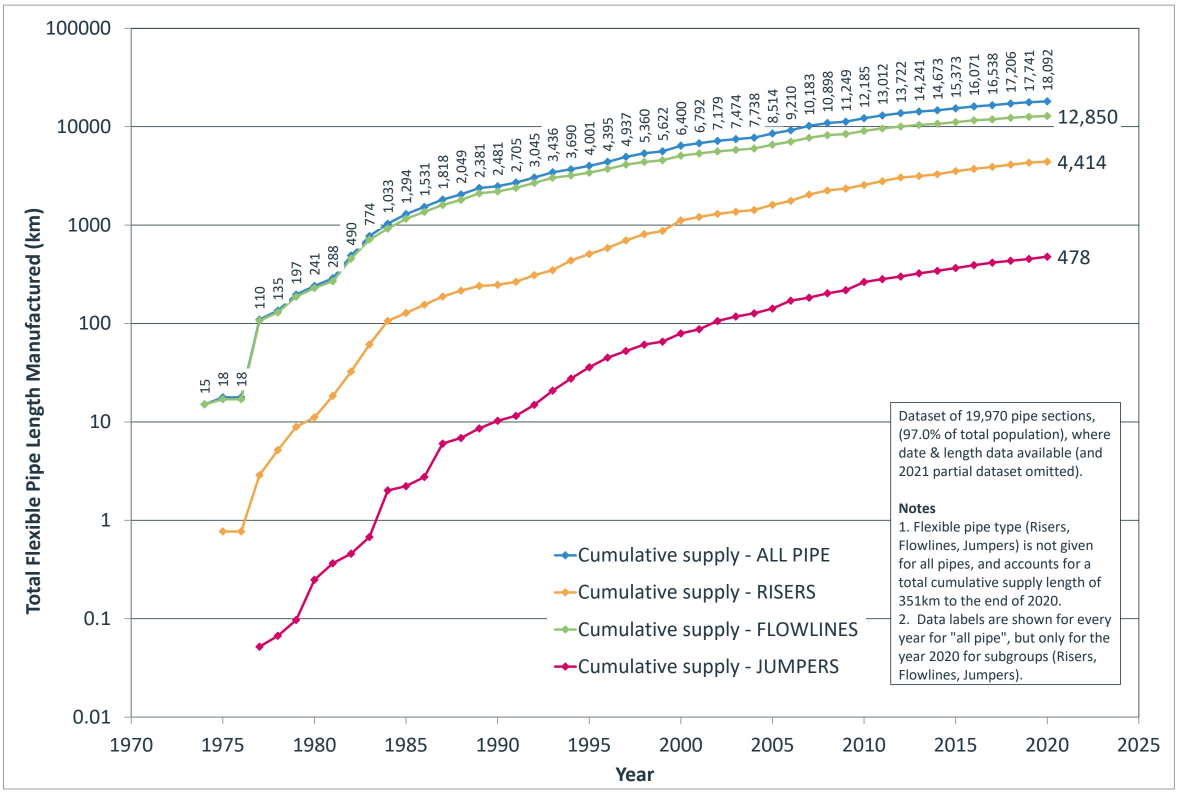


Figure 3.36 Total Cumulative Flexible Pipe Length Manufactured (log scale)

Table 3.4 Flexible Pipe Operational Experience during 5-year Periods

Period	Pipe-Years Experience (in period)		
	Risers	Flowlines & Jumpers	Riser, Flowlines & Jumpers
1976 – 1981	144	615	759
1981 – 1986	1,083	2,718	3,802
1986 – 1991	2,633	6,953	9,586
1991 – 1996	4,061	12,251	16,313
1996 – 2001	6,753	19,455	26,208
2001 – 2006	9,384	25,773	35,157
2006 – 2011	12,619	35,979	48,597
2011 – 2016	15,627	45,235	60,862
2016 – 2021	17,924	50,788	68,712
Total	**70,229**	**199,768**	**269,997**

Note:
1. Operational experience is based on datasets which include all of the following parameters; supply date, pipe type (riser, flowline, jumper), and number of pipe sections. This dataset represents 94.0% of all pipe sections in the population database.
2. The total figure (269,997 pipe-years) excludes 15 pipe-years associated with 2 individual years prior to the first 5-year block. Combining these figures gives the total figure of 270,012 pipe-years (Figure 3.38).

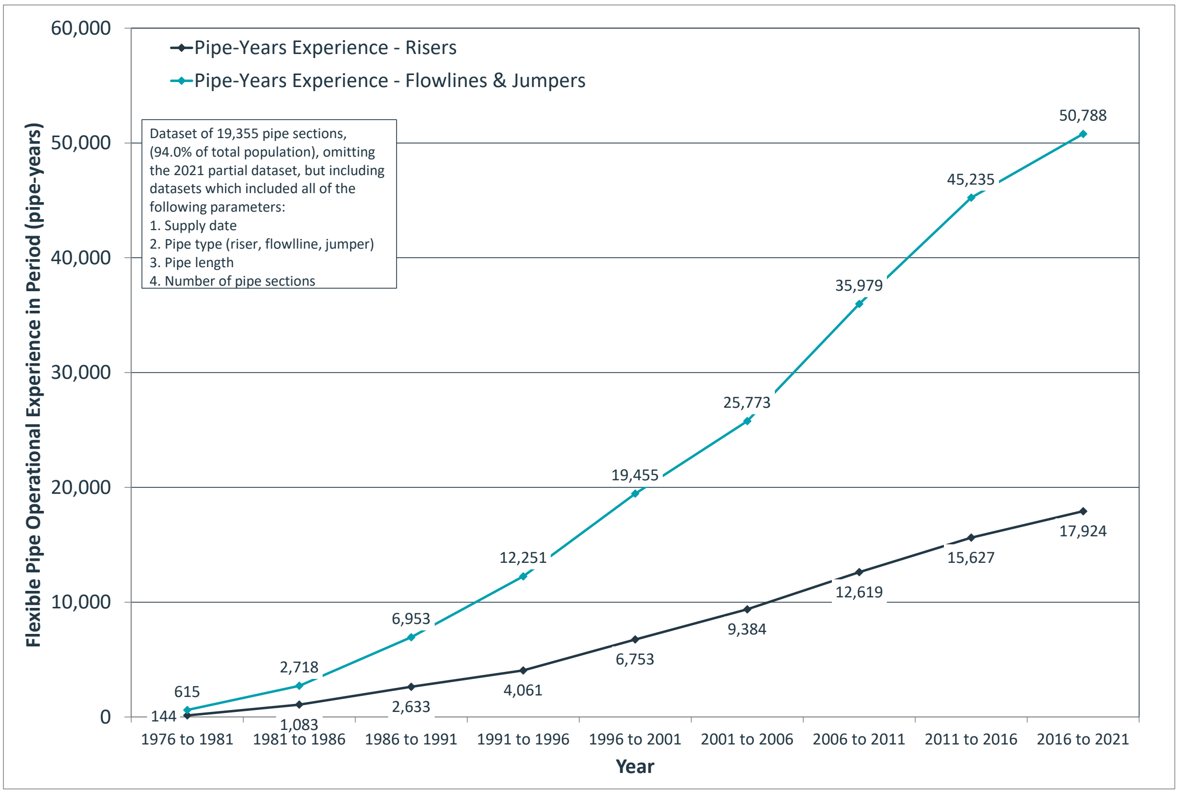


Figure 3.37 Flexible Pipe Operational Experience (pipe-years)

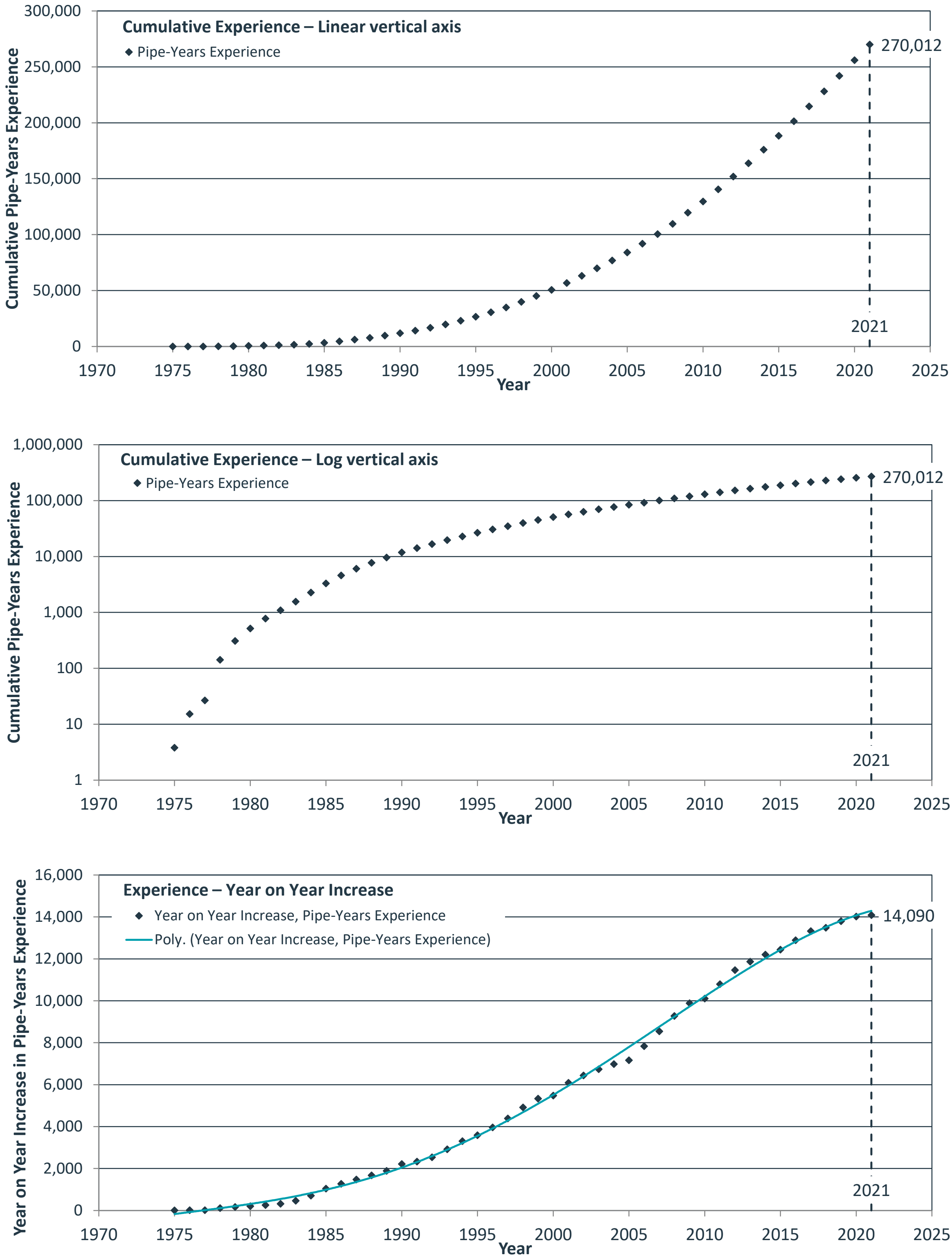


Figure 3.38 Flexible Pipe Operational Experience (all pipe, annualised trends)

4.0 Flexible Pipe Database : Experience of Damage & Failure

4.1 Objective & Approach

The Sureflex JIP has collected up to date information relating to *Damage* and *Failure* of unbonded flexible pipe and collated this information in a database. A de-sensitised version of this database is made available to JIP members. The principal objective of the JIP is to improve the wider industry understanding of the key mechanisms that affect the ability of the pipe to perform its function through any stage of its life cycle, and thereby to allow those threats to be mitigated through a risk review process throughout the pipe life.

A secondary use of this data, in combination with flexible pipe population data presented in Section 3.0, is to allow users to estimate the *Damage* / *Failure* rates of flexible pipes to provide input to quantitative risk assessments. However, **it is recommended that caution be applied in the use of this data to determine failure probabilities of a specific flexible pipe system. Whilst the data collected is extensive, and represents the most comprehensive global database available within the industry, each flexible pipe system will have specific threats which must be considered**. The key points that should be considered when determining probabilities based on these datasets are:

- Risk applicability to the specific flexible pipe system e.g. static / dynamic, service type, cross-section family and design variations, host facility type (if applicable), operating conditions, inspectability etc.
- Some failure modes have been resolved by design or mitigated in operation by the industry,
- Flexible pipe system designs and utilisations do vary from field to field, and a field-specific risk assessment is therefore necessary,
- A number of *Damage* / *Failure* conditions are the result of operations outwith design limits, and the applicability of such cases to a new system with increased knowledge of actual operating limits may be unrepresentative. Some failures also occurred during pro-active integrity-driven pressure tests in hydrocarbon-free environments,
- Due to the relatively young age of the operational flexible pipe inventory (Section 3.6.1) the *Damage* and *Failure* experience relating to late life failure mechanisms have not reached a stable equilibrium. Whilst the Failure-*Leak* incident rates continue to decline, the Failure-*Rupture* incident rates for *Riser* applications have shown a significant increase in the last decade, in part due to emergent failure mechanisms. Incidents of such age-related mechanisms may increase over time as the global flexible pipe inventory ages.

A significant focus of the Sureflex JIP is to understand the differences between the types of defects that result from the varying *Damage* and *Failure* mechanisms and furthermore to assess the differing levels of *Damage* and *Failure* by various mechanisms, including pipes which have been shut-down or replaced due to integrity concerns. There have been various industry studies over the preceding 25 years, and in some cases there is evidence that any "defect" or change-out of a pipe has been categorised as a pipe *Failure*. A degree of caution is required in the interpretation of such datasets when establishing failure rates, and as such the Sureflex JIP database makes significant effort to accurately categorise historical *Damage* and *Failure* incidents to give the user value in assessing operational threats to their specific flexible pipe systems. Further information on the "status" definitions is presented in Section 4.1.1 below.

The JIP has intentionally focussed on *Damage* and *Failure* mechanisms that occur in the installation and operating phases of the flexible pipe, as it is that experience which the long-term users (i.e. operators) have the highest quality data for. There are a limited number of *Damage* and *Failure* events that are known to have occurred at FAT or load-out stages. However, it is the conclusion of the JIP that members are unlikely to have the full information relating to FAT incidents, and most load-out incidents that are identified would normally be rectified prior to handover to the operator. Moreover, in the event of FAT failure, re-termination or manufacture of a replacement pipe will typically be undertaken. As such, the statistics presented herein focus on the *Damage* and *Failure* mechanisms that are applicable after the pipe has been handed over to and accepted by the user / operator.

The *Damage* and *Failure* data presented within this report is based on information from the following sources:

- Input from JIP members via the Incident Reporting Template (presented in Appendix E),
- Input from discussions with both JIP member and non-member organisations,
- Experience / database from previous Sureflex JIP (Ref. [13]),
- Information from Wood internal knowledge,
- Public domain information.

Information from all sources is intentionally "de-sensitised" so that any *Damage / Failure* incident is not readily attributable to a specific operator / field. This approach encourages open and full engagement with the operational users of flexible pipe and is consistent with preceding JIPs. In addition, the presentation of data linking a degradation mechanism to a specific field / operator does not add value in the understanding of the causal factors of the *Damage / Failure* in most cases.

4.1.1 Flexible Pipe Degradation Definitions

An *Incident* is used to describe an event or occurrence in which flexible pipe system degradation is identified. *Incidents* of different levels of degradation are categorised according to the following criteria:

- The "Status" categorisation of the flexible pipe in question. These criteria are defined in Table 4.1, below. The key differentiators, and linkages, between *Damage* and *Failure* are also shown schematically in Figure 4.1.
- The *Damage / Failure* Cause, or mechanism. There are a large number of mechanisms encompassed within the database, and as such the Definitions are presented in Appendix A, Table A.1. Potential failure modes for which no operational experience have been reported are shown (shaded) in the Table A.1 but are not replicated in the datasets within this section of the report.

Table 4.1 Definitions relating to Flexible Pipe "Status"

Status	Definition
Minor defect / damage	Whilst there may be some overlap between this criteria and the *Damage* criteria (below), the main differentiator is that in the case of a pipe that has some minor defect / damage, it is not anticipated that the defect will progress to failure, and it is unlikely to materially affect the original design service life.
Damage (failure initiator)	An issue / anomaly which degrades the flexible pipe construction / performance over time. Damage tends to be a failure initiator, which if left undetected could progress through a **Failure Mechanism**, leading to an ultimate **Failure** condition in the short to medium term. There are cases where a damaged flexible pipe may remain in operation following the identification of damage if the risk can be defined and managed / mitigated, but it is possible that the original design service life may be impacted. In addition, partial failures of connected systems (e.g. MWA tether failure, or other ancillary equipment) which may not have immediately damaged the flexible pipe, but represent system failures requiring mitigation, are categorised as Damage. Cases where a pipe is unable to perform the intended design function are normally included as damage cases (e.g. reduced capacity or blockage).
Shut-down (integrity concern)	A flexible pipe which has been shut down due to an integrity concern. A common example of this would be if one pipe fails in a field through a failure mechanism that is likely to affect additional pipes with common design and operating conditions. Based on existing operational mitigations and risk assessment, a user may elect to shut-down pipes that are likely to be subject to the same failure risk to avoid the failure consequences. Alternatively, flexible pipes may be shut-down based on the results of an engineering desktop analysis without direct evidence of damage. In cases where a pipe is shutdown as a result of one of these concerns and is subsequently removed from service, the case remains classified in this status.

Failure
 	
(distinguished as either *Leak* or *Rupture*)
	Failure of the primary bore containment (the polymer internal pressure sheath) of the pipe at either operating or design conditions. Failure may be categorised as a ***Leak*** or ***Rupture***, as follows:
	• **Failure-Leak** Relatively low level leakage through an internal pressure sheath defect
	• **Failure-Rupture** Failure of bore containment through major internal pressure sheath defect e.g.:
	  ○ Crack / extrusion of IPS over >45° circumference and / or length equivalent to one pipe ID,
	  ○ Catastrophic failure / separation of the flexible pipe.
	
	Failures resulting in either a *Leak* or a *Rupture* may be the result of failure initiation (*Damage*) from another pipe layer (e.g. corrosion / cracking of multiple armour wires leading to loss of support, or associated ancillary equipment). If a *Damage* case develops to *Failure*, only the *Failure* case is counted in terms of the *Damage* and *Failure* statistics.

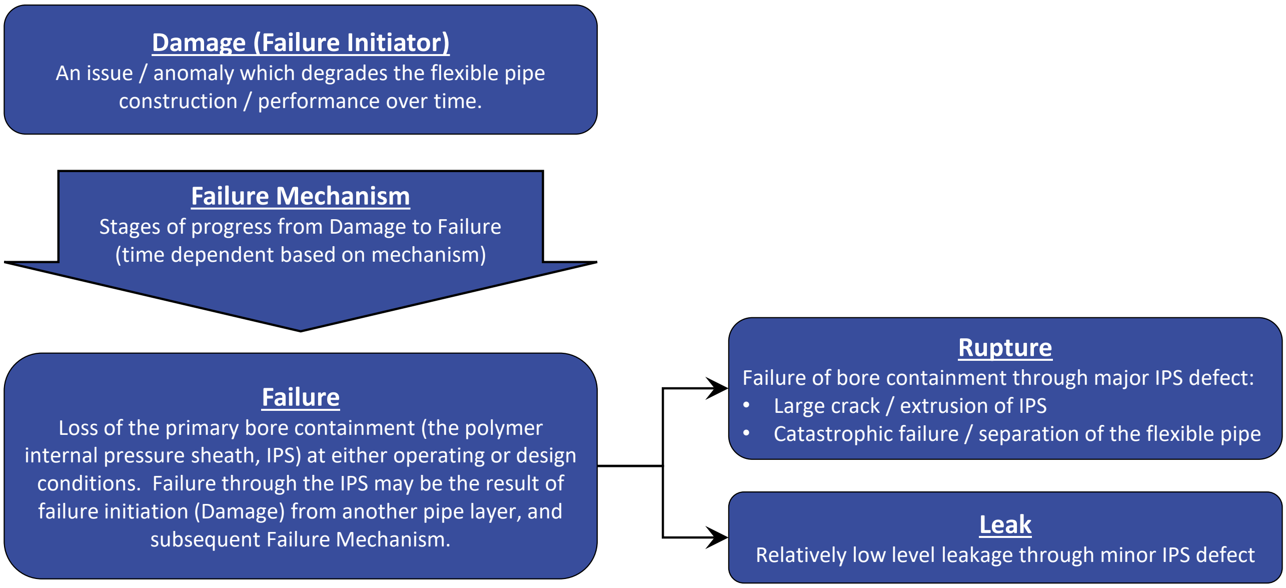


Figure 4.1 Definitions : Damage & Failure Categorisation

4.1.2 Intentional Inclusions / Exclusions to the Database Statistics

The sources of the *Damage* and *Failure* statistics are listed in Section 4.1, above. There are a number of specific cases which have intentionally been included / excluded, which the user of this data should be aware of. The main inclusions / exclusions are summarised as follows:

<u>Inclusions:</u>

- Where 2 completely independent *Damage* / *Failure* incidents have occurred on a single pipe they are included as separate incident cases.

<u>Exclusions:</u>

- Initiating *Damage* incidents that directly lead to a related *Damage* / *Failure* mechanism are not counted e.g. annulus flooding is not counted if it ultimately leads to corrosion related catastrophic failure.
- *Damage* caused to connected systems, where the flexible pipe may be the trigger / initiator but is not directly affected by the issue e.g. FLIP, refer to Section 4.1.2.1 for description of industry experience and guidance. However, the database does include 5 incidents where risers were shut-down due to the occurrence of FLIP.
- *Damage* / *Failure* of flexible pipes resulting from catastrophic failures of other systems e.g.
    - loss of mooring integrity leading to riser Damage, refer to Section 4.1.2.2 for description of industry experience.
    - major incident in topsides process system leading to large scale event including, but not limited to, flexible pipe Damage / Failure, refer to Section 4.1.2.3.
- *Damage / Failure* experience which has been gathered relating to incidents since 01/07/2021 is included in the statistics of overall experience, presented in Table 4.2 to Table 4.7. However, this experience has been intentionally omitted from the failure rate statistics, which are presented in 5-year blocks up to and including 01/07/2021, as both the population and *Damage / Failure* data and statistics are incomplete for this period.

4.1.2.1 Guidance Note, Flow Induced Pulsation (FLIP)

Flow Induced Pulsations can occur in unbonded flexible pipes when dry gas flows over the internal ridges of the internal carcass. In certain cases these pulsations can interact with side branch connections in connected rigid pipework, both upstream and downstream, with the potential to cause significant vibration in associated rigid pipework leading to fatigue failure. All the industry experience, including extensive joint industry studies, has shown that the flexible pipe itself is only the initiator and is not directly affected itself. As such, FLIP type issues are excluded from the main JIP database. However, ***the significant safety threats and production impacts relating to the risks of failures in connected topsides pipework should not be underestimated.*** *A summary of industry experience related to this phenomenon is presented below.*

Over the last 20 years; vibration, dynamics and noise consultants have been involved in troubleshooting FLIP issues on numerous global FPSOs, mainly based on topsides pipework vibration, dynamic stress and pressure pulsation measurements. These measurements can be used to assess the risk of a FLIP induced piping fatigue failure for both the topsides and subsea piping associated with the flexible gas riser. One asset (a significant gas export facility) has experienced a significant hydrocarbon release leading to an extended shutdown, while others, having recognised the concern, have had to limit production / flowrates to below the onset-of-FLIP condition whilst mitigation measures are evaluated and implemented. As such, a FLIP-induced piping fatigue failure can result in not just significant safety concerns but also a substantial impact on production. It is of note that FLIP is gas flow dependent and hence different piping sections are subject to excessive vibration/stress at different flowrates.

No actual subsea piping failures have been reported due to FLIP excitation. However, potential fatigue failure locations have been identified for at least 5 assets. For one operator the FLIP concern was sufficiently significant for them to fund a full scale model of a subsea manifold which was built and tested in a water test tank to better evaluate the scale of the vibration issue. This ultimately led to modifications being evaluated (using the same test facilities), and the development of a screening assessment methodology which was employed for subsequent pipe designs.

It is the internal corrugations of the carcass in a rough bore pipe that initiate the pressure pulsations which act as a trigger to FLIP vibration threats. As such, FLIP can be prevented through cross-section design by use of either a:

- *Smooth bore riser, i.e. a riser with no dedicated carcass layer and where collapse resistance is provided by the pressure armour layer. Whilst there is a need for more stringent control of annulus venting and shutdown procedures (depressurisation rates) to avoid collapse of a smooth bore internal sheath, a limited number of operators have implemented this change to either remediate FLIP issues in operation, or to mitigate the threat at the design stage (e.g. Ref. [23]).*
- *FLIP resistant carcass design, i.e. a traditional rough bore carcass design with an additional strip incorporated into the forming process to give a smoother bore finish. FLIP resistant carcass designs have been a significant technological development in flexible pipe design since the last iteration of the Sureflex JIP. Several FLIP resistant carcass pipes have been delivered and have entered operation in static applications. Whilst manufacturers have qualified and are delivering FLIP resistant carcass designs for dynamic applications, there is no operational experience to date. It should be noted that FLIP resistant carcass designs may not be qualified for all carcass material grades. See also references Ref. [40], Ref. [41], Ref. [42], Ref. [43].*

If the use of a smooth bore pipe or FLIP resistant carcass is not feasible, for design stage projects a screening assessment based on the gas properties and flows, and the carcass geometry, can be used to identify the minimum flowrate at which FLIP might start, refer to API 17J / B updates for guidance (see also Sections 8.2 and 8.7). It is only above this "onset velocity" where the details of the topsides and subsea piping design need to be reviewed in detail, and if necessary, re-designed or modified to prevent the significant pressure pulsation levels associated with (subsea *and topsides) sidebranch acoustic resonance.*

For operational assets, it is normally recommended that a site measurement survey is first undertaken to determine the extent and magnitude of the FLIP-induced pipework vibration. This has typically been limited to the topsides pipework and hence the measured data will have to be assessed in detail to identify the contribution of the subsea piping. In a very limited number of cases, operators have deployed subsea monitoring programs in parallel. Detailed modelling will then allow at-risk pipework to be identified/confirmed and assessed, and potential design modifications evaluated. There is good industry experience of designing simple braces for both topsides and subsea piping (ROV-deployed), to mitigate the long-term risk of a FLIP-induced fatigue failure. Alternatively, operators may elect to install subsea and topsides monitoring systems, i.e. for use as an operational mitigation measure (to identify and then help avoid flowrates where FLIP occurs).

There have been a number of cases where FLIP onset has not been identified during initial operations until a time when the operating regime has changed and moved into the onset range, sometimes many years into the asset life. Most commonly this is the result of increases in gas flowrates which raise the velocity above the onset limit. This effectively results in the FLIP vibration being "switched on". Another possibility would be where a system with moist gas (or liquid chemical injection) changes to dry gas and could take the system into a FLIP regime. A practical example of this was an asset where a new dehydration package was commissioned which reduced the liquid content in the export gas and led to FLIP being experienced where previously there had been no issues.

It should be noted that in general, FLIP piping vibration is "mid-frequency", i.e. between 100 and 1,000 Hz, and hence significant piping stress levels can lead to a fatigue failure in a relatively short period of time (days or weeks at a constant flowrate). As a result, it is normally recommended that if FLIP is experienced, the gas flowrate should be reduced or other measures implemented (e.g. introduction of small fluid volumes, Ref. [35]) until the FLIP stops, to minimise the risk of a fatigue failure until appropriate mitigation measures can be implemented.

Further information relating to industry studies / guidance on the topic of FLIP are summarised in Section 8.7 of this report.

4.1.2.2 Guidance Note, Catastrophic Failures – Loss of Mooring Integrity

*The focus of the Sureflex Damage / Failure database is on the mechanisms that directly affect the flexible pipe, **and** can be reasonably controlled / mitigated within the local area of the concern. As such, it is not the intent of the JIP to include any Damage / Failure associated with significant mooring failure and breach of design offset requirements in the failure database.*

There have been a number of catastrophic mooring incidents across the globe that are reported in public domain sources. These have occurred across a range of floating production facilities i.e. FPSO, semi-submersible, and TLP type vessels.

However, it is worth highlighting here experience which demonstrates the robustness of flexible pipes in such conditions. In one instance, an operator experienced a significant "off station" event as the result of mooring system failure during a storm. Whilst much of the seabed infrastructure was severely damaged with some riser bases being displaced several hundred metres, none of the flexible riser components failed. There was significant Damage to the risers and ancillary equipment, but the only failure / loss of containment was caused by the failure of the (gas) topsides rigid spools which were overloaded by the connected riser.

4.1.2.3 *Guidance Note, Catastrophic Failures – Major Incidents initiated elsewhere*

*The inventory of hydrocarbons carried by pipeline and riser systems can be large, and the uncontrolled release of such inventories can lead to catastrophic incidents, most notable in the Piper Alpha disaster of 1988, Ref. [73]. One of the most significant factors in mitigating the escalation of such events is the control of the inventory envelope through suitable positioning of ESDVs, SSIVs and the control (and depressurisation) of the isolated inventory. However, the focus of the Sureflex Damage / Failure database is on the mechanisms that directly affect the flexible pipe, **and** can be reasonably controlled / mitigated within the local area of the concern. As such, any major incident in a topsides process system leading to large scale event including, but not limited to, flexible pipe Damage / Failure is not intended to be captured within the database.*

4.2 Limitations of Database Information

The Sureflex database represents the most comprehensive global database relating to degradation, damage, and failure of unbonded flexible pipes, having been maintained and expanded since the original 2001, Ref. [17], and subsequent 2010, Ref. [14] & [15], and 2017, Ref. [13], studies. However, it is accepted that the operator-led damage and failure data is unlikely to be fully representative and capture **every** incident of flexible pipe degradation / failure.

One of the most significant challenges of maintaining damage and failure statistics relates to the fact that data is normally gathered periodically as opposed to at the time of the damage / failure incident. This relies heavily on the corporate knowledge / memory of the organisation for retrospective reporting, which can degrade over time. In order to mitigate such data "loss", a standardised template for reporting damage and failure experience is used, as presented in Appendix E. To minimise the potential for damage / failure experience to go unreported, it is recommended that reports are populated at the time of identification of damage / failure, and updated following any investigative close-out.

Care must be taken in the selective use of statistics from within the JIP report for the following reasons:

- The effect of the population statistics to the applied adjustment factors, noted in Sections 3.2 and 3.6.1.
- As noted in Section 4.1, it is recommended that caution be applied in the use of this data to determine failure probabilities for a specific flexible pipe system as each pipe system is likely to have different risk factors that will affect the likelihood of a particular threat.
- As noted in Section 4.3.3, data relating to the timing of damage / failure incidents is available for approximately 85% of reported incidents. As such, damage / failure rates are likely to be slightly underestimated through the timeline. In addition, it is important to note that the damage / failure dates (and corresponding incident rates) are attributed to when the damage / failure was identified / reported. In the case of failure, this often occurs well after the initiating damage event itself.

4.3 Database Results : Experience of Damage & Failure

4.3.1 All Data

The *Damage* and *Failure* database is populated with 874 individual incidents. These incidents occur over:

- 40 separate *Damage / Failure* causes (plus 1 cause of disputed mechanism)
    - **Note**: 48 "potential causes" were identified and used to populate the database. However, there has been no reported operational experience to date relating to 8 of those "potential causes", these damage mechanisms are shaded in grey in Appendix A.
- 5 separate "status" criteria, as defined in Table 4.1, above.

The full dataset of incidents are presented in a series of tables over the following pages:

- Matrix of number of incidents, defined by causes (rows) and status (columns). Each individual populated cause is logically listed and grouped into those affecting either specific layers of the flexible pipe, or into "ancillary equipment" or "global pipe defect" groupings, relating to;
    - Table 4.2, All flexible pipe
    - Table 4.3, Risers only (subset of Table 4.2)
    - Table 4.4, Flowlines & Jumpers (subset of Table 4.2)
- Similar to the tables noted above, the incident statistics of the populated causes are summed into 11 consolidated groupings based on the pipe layer or the alternative causal grouping.
    - Table 4.5, All flexible pipe
    - Table 4.6, Risers only (subset of Table 4.5)
    - Table 4.7, Flowlines & Jumpers (subset of Table 4.5)

Note that for failures where there are no reported incidents (in the "subset" tables) the entire row is shaded.

Descriptions, discussion, and mitigations relating to the most critical *Damage* and *Failure* causes are included in Section 4.4 of this report. However, some initial observations on the categorisation of the 874 reported *Damage / Failure* incidents are:

- Of the 874 incidents, 679 (77.7%) are related to Risers, the remaining 195 (22.3%) are attributed to Flowlines & Jumpers.
    - For comparison, in the previous iteration of this JIP, Ref. [13], there were 584 recorded incidents of which 465 (79.6%) related to Risers and 119 (20.4%) related to Flowlines & Jumpers.
- 42.4% (371 cases) were classed as *Damage*, with no Loss of Containment.
    - 341 Riser Damage incidents
    - 30 Flowline & Jumper Damage incidents
- 16.8% (147 cases) resulted in a Loss of Containment which was classified as a *Leak*.
    - 71 Riser Leak incidents
    - 76 Flowline & Jumper Leak incidents
- 3.9% (34 cases) resulted in a Loss of Containment which was classified as a *Rupture* (a desensitised summary of these most critical failures is included in Table 4.18).
    - 25 Riser Rupture incidents
    - 9 Flowline & Jumper Rupture incident
- 19.8% (173 cases) related to cases where a pipe was reported to have a minor defect (definition as per Table 4.1 that these cases are unlikely to materially affect the original design service life).
- 17.0% (149 cases) related to cases where a pipe was shut-down due to an integrity concern, but *Damage* was not identified.

Table 4.2 Degradation Statistics, by Cause & Pipe Status, All Pipe

Damage / Failure Cause	Number of cases, by status					Total	%
	Minor defect / damage	Shut-down (integrity concern)	Damaged (failure initiator)	Failed - leak	Failed - rupture		
Line Recovered Proactively - No significant damage / defect identified		44				**44**	**5.0%**
Carcass Failure - Fatigue				1		**1**	**0.1%**
Carcass Failure - Multilayer PVDF Collapse		9	24	6		**39**	**4.5%**
Carcass Failure - Tearing / Pullout	1	5	6	5		**17**	**1.9%**
Internal Damage - Pigging			2			**2**	**0.2%**
Internal Pressure Sheath - Ageing		27	1	21		**49**	**5.6%**
Internal Pressure Sheath - End Fitting Pull-out	2	19	3	19		**43**	**4.9%**
Internal Pressure Sheath - Fatigue / Fracture / Microleaks	2	1	3	9		**15**	**1.7%**
Internal Pressure Sheath - Smooth Bore Liner Collapse	3			6	3	**12**	**1.4%**
Tensile Armour Wire Breakage - in / close to end fitting				3	1	**4**	**0.5%**
Tensile Armour Wire Breakage - in main pipe section		1	12	1	8	**22**	**2.5%**
Tensile Armours - Birdcaging			6	13	1	**20**	**2.3%**
Corrosion of Armours - Major / Catastrophic			5	13	15	**33**	**3.8%**
Corrosion of Armours - Moderate	5	4	7			**16**	**1.8%**
Annulus Flooding - Cause Unknown	22	5	90			**117**	**13.4%**
Annulus Flooding - Defective Annulus Vent System	14		4			**18**	**2.1%**
Annulus Flooding - Outer Sheath Damage - Ageing / Fracture	1		4			**5**	**0.6%**
Annulus Flooding - Outer Sheath Damage - Mechanical / Impact / Wear	45	18	99			**162**	**18.5%**
Annulus Flooding - Permeated Liquids	2					**2**	**0.2%**
Outer Sheath Damage - Annulus NOT flooded - Ageing / Fracture	4					**4**	**0.5%**
Outer Sheath Damage - Annulus NOT flooded - Mechanical / Impact / Wear	21		6			**27**	**3.1%**
End Fitting Leak / Failure			1	25	3	**29**	**3.3%**
Ancillary Equipment - Bend Stiffener - Connection / Interface	7	2	28			**37**	**4.2%**
Ancillary Equipment - Bend Stiffener - 2 part failure			11			**11**	**1.3%**
Ancillary Equipment - Bend Stiffener - other	4		2	2		**8**	**0.9%**
Ancillary Equipment - Buoyancy Modules	1	1				**2**	**0.2%**
Ancillary Equipment - Hang-off Failure			1			**1**	**0.1%**
Ancillary Equipment - Hold-down Failure (tethers / clamps / connections)	2		6	1		**9**	**1.0%**
Ancillary Equipment - Mid Water Arch	2	2	5	1		**10**	**1.1%**
Ancillary Equipment - Vent System Anomalies / Blockage	21	3	18			**42**	**4.8%**
Ancillary Equipment - Other				2		**2**	**0.2%**
Global Pipe Defect - Dropped Object / 3rd Party Interaction / Dragging	7	2	3	1		**13**	**1.5%**
Global Pipe Defect - Excess Tension					1	**1**	**0.1%**
Global Pipe Defect - Excess Torsion			2	1	1	**4**	**0.5%**
Global Pipe Defect - Flow Induced Pulsation (FLIP) causing wider system effect		5				**5**	**0.6%**
Global Pipe Defect - Ovalisation			4			**4**	**0.5%**
Global Pipe Defect - Overbend / Pressure Armour Unlock			5	12	1	**18**	**2.1%**
Global Pipe Defect - Rough Bore Collapse			2	1		**3**	**0.3%**
Global Pipe Defect - Upheaval Buckling	3		1	3		**7**	**0.8%**
Global Pipe Defect - Pipe Blockage (wax/hydrates/other)	3	1	9			**13**	**1.5%**
Global Pipe Defect - Excess Marine Growth			1			**1**	**0.1%**
Failure Mechanism Disputed	1			1		**2**	**0.2%**
Total	**173**	**149**	**371**	**147**	**34**	**874**	**100.0%**
%	**19.8%**	**17.0%**	**42.4%**	**16.8%**	**3.9%**	**100.0%**	

Table 4.3 Degradation Statistics, by Cause & Pipe Status, Risers only (subset of Table 4.2)

Damage / Failure Cause	Number of cases, by status					Total	%
	Minor defect / damage	Shut-down (integrity concern)	Damaged (failure initiator)	Failed - leak	Failed - rupture		
Line Recovered Proactively - No significant damage / defect identified		38				**38**	**5.6%**
Carcass Failure - Fatigue				1		**1**	**0.1%**
Carcass Failure - Multilayer PVDF Collapse		7	24	6		**37**	**5.4%**
Carcass Failure - Tearing / Pullout	1		6	2		**9**	**1.3%**
Internal Damage - Pigging			1			**1**	**0.1%**
Internal Pressure Sheath - Ageing		20	1	6		**27**	**4.0%**
Internal Pressure Sheath - End Fitting Pull-out		10	3	15		**28**	**4.1%**
Internal Pressure Sheath - Fatigue / Fracture / Microleaks	2		2	5		**9**	**1.3%**
Internal Pressure Sheath - Smooth Bore Liner Collapse	2			3	3	**8**	**1.2%**
Tensile Armour Wire Breakage - in / close to end fitting				3	1	**4**	**0.6%**
Tensile Armour Wire Breakage - in main pipe section		1	12	1	8	**22**	**3.2%**
Tensile Armours - Birdcaging			6	7		**13**	**1.9%**
Corrosion of Armours - Major / Catastrophic			4		12	**16**	**2.4%**
Corrosion of Armours - Moderate	4	2	7			**13**	**1.9%**
Annulus Flooding - Cause Unknown	21	4	89			**114**	**16.8%**
Annulus Flooding - Defective Annulus Vent System	12		4			**16**	**2.4%**
Annulus Flooding - Outer Sheath Damage - Ageing / Fracture	1		4			**5**	**0.7%**
Annulus Flooding - Outer Sheath Damage - Mechanical / Impact / Wear	32	17	87			**136**	**20.0%**
Annulus Flooding - Permeated Liquids	2					**2**	**0.3%**
Outer Sheath Damage - Annulus NOT flooded - Ageing / Fracture						**0**	**0.0%**
Outer Sheath Damage - Annulus NOT flooded - Mechanical / Impact / Wear	14		5			**19**	**2.8%**
End Fitting Leak / Failure			1	8		**9**	**1.3%**
Ancillary Equipment - Bend Stiffener - Connection / Interface	7	2	28			**37**	**5.4%**
Ancillary Equipment - Bend Stiffener - 2 part failure			11			**11**	**1.6%**
Ancillary Equipment - Bend Stiffener - other	4		2	2		**8**	**1.2%**
Ancillary Equipment - Buoyancy Modules	1	1				**2**	**0.3%**
Ancillary Equipment - Hang-off Failure			1			**1**	**0.1%**
Ancillary Equipment - Hold-down Failure (tethers / clamps / connections)	2		6	1		**9**	**1.3%**
Ancillary Equipment - Mid Water Arch	2	2	5	1		**10**	**1.5%**
Ancillary Equipment - Vent System Anomalies / Blockage	20	3	18			**41**	**6.0%**
Ancillary Equipment - Other				2		**2**	**0.3%**
Global Pipe Defect - Dropped Object / 3rd Party Interaction / Dragging	2		1			**3**	**0.4%**
Global Pipe Defect - Excess Tension					1	**1**	**0.1%**
Global Pipe Defect - Excess Torsion						**0**	**0.0%**
Global Pipe Defect - Flow Induced Pulsation (FLIP) causing wider system effect		5				**5**	**0.7%**
Global Pipe Defect - Ovalisation						**0**	**0.0%**
Global Pipe Defect - Overbend / Pressure Armour Unlock			3	6		**9**	**1.3%**
Global Pipe Defect - Rough Bore Collapse				1		**1**	**0.1%**
Global Pipe Defect - Upheaval Buckling						**0**	**0.0%**
Global Pipe Defect - Pipe Blockage (wax/hydrates/other)			9			**9**	**1.3%**
Global Pipe Defect - Excess Marine Growth			1			**1**	**0.1%**
Failure Mechanism Disputed	1			1		**2**	**0.3%**
Total	**130**	**112**	**341**	**71**	**25**	**679**	**100.0%**
%	**19.1%**	**16.5%**	**50.2%**	**10.5%**	**3.7%**	**100.0%**	

Table 4.4 Degradation Statistics, by Cause & Pipe Status, Flowlines & Jumpers only (subset of Table 4.2)

Damage / Failure Cause	Number of cases, by status					Total	%
	Minor defect / damage	Shut-down (integrity concern)	Damaged (failure initiator)	Failed - leak	Failed - rupture		
Line Recovered Proactively - No significant damage / defect identified		6				**6**	**3.1%**
Carcass Failure - Fatigue						**0**	**0.0%**
Carcass Failure - Multilayer PVDF Collapse		2				**2**	**1.0%**
Carcass Failure - Tearing / Pullout		5		3		**8**	**4.1%**
Internal Damage - Pigging			1			**1**	**0.5%**
Internal Pressure Sheath - Ageing		7		15		**22**	**11.3%**
Internal Pressure Sheath - End Fitting Pull-out	2	9		4		**15**	**7.7%**
Internal Pressure Sheath - Fatigue / Fracture / Microleaks		1	1	4		**6**	**3.1%**
Internal Pressure Sheath - Smooth Bore Liner Collapse	1			3		**4**	**2.1%**
Tensile Armour Wire Breakage - in / close to end fitting						**0**	**0.0%**
Tensile Armour Wire Breakage - in main pipe section						**0**	**0.0%**
Tensile Armours - Birdcaging				6	1	**7**	**3.6%**
Corrosion of Armours - Major / Catastrophic			1	13	3	**17**	**8.7%**
Corrosion of Armours - Moderate	1	2				**3**	**1.5%**
Annulus Flooding - Cause Unknown	1	1	1			**3**	**1.5%**
Annulus Flooding - Defective Annulus Vent System	2					**2**	**1.0%**
Annulus Flooding - Outer Sheath Damage - Ageing / Fracture						**0**	**0.0%**
Annulus Flooding - Outer Sheath Damage - Mechanical / Impact / Wear	13	1	12			**26**	**13.3%**
Annulus Flooding - Permeated Liquids						**0**	**0.0%**
Outer Sheath Damage - Annulus NOT flooded - Ageing / Fracture	4					**4**	**2.1%**
Outer Sheath Damage - Annulus NOT flooded - Mechanical / Impact / Wear	7		1			**8**	**4.1%**
End Fitting Leak / Failure				17	3	**20**	**10.3%**
Ancillary Equipment - Bend Stiffener - Connection / Interface						**0**	**0.0%**
Ancillary Equipment - Bend Stiffener - 2 part failure						**0**	**0.0%**
Ancillary Equipment - Bend Stiffener - other						**0**	**0.0%**
Ancillary Equipment - Buoyancy Modules						**0**	**0.0%**
Ancillary Equipment - Hang-off Failure						**0**	**0.0%**
Ancillary Equipment - Hold-down Failure (tethers / clamps / connections)						**0**	**0.0%**
Ancillary Equipment - Mid Water Arch						**0**	**0.0%**
Ancillary Equipment - Vent System Anomalies / Blockage	1					**1**	**0.5%**
Ancillary Equipment - Other						**0**	**0.0%**
Global Pipe Defect - Dropped Object / 3rd Party Interaction / Dragging	5	2	2	1		**10**	**5.1%**
Global Pipe Defect - Excess Tension						**0**	**0.0%**
Global Pipe Defect - Excess Torsion			2	1	1	**4**	**2.1%**
Global Pipe Defect - Flow Induced Pulsation (FLIP) causing wider system effect						**0**	**0.0%**
Global Pipe Defect - Ovalisation			4			**4**	**2.1%**
Global Pipe Defect - Overbend / Pressure Armour Unlock			2	6	1	**9**	**4.6%**
Global Pipe Defect - Rough Bore Collapse			2			**2**	**1.0%**
Global Pipe Defect - Upheaval Buckling	3		1	3		**7**	**3.6%**
Global Pipe Defect - Pipe Blockage (wax/hydrates/other)	3	1				**4**	**2.1%**
Global Pipe Defect - Excess Marine Growth						**0**	**0.0%**
Failure Mechanism Disputed						**0**	**0.0%**
Total	**43**	**37**	**30**	**76**	**9**	**195**	**100.0%**
%	**22.1%**	**19.0%**	**15.4%**	**39.0%**	**4.6%**	**100.0%**	

Table 4.5 Degradation Statistics, by Cause & Pipe Status, Grouped by Pipe Layer, All Pipe

Damage / Failure Cause	Number of cases, by status					Total	%
	Minor defect / damage	Shut-down (integrity concern)	Damaged (failure initiator)	Failed - leak	Failed - rupture		
Line Recovered Proactively - No significant damage / defect identified		44				**44**	**5.0%**
Carcass	1	14	30	12		**57**	**6.5%**
Internal Damage - Pigging			2			**2**	**0.2%**
Internal Pressure Sheath	7	47	7	55	3	**119**	**13.6%**
Armours	5	5	30	30	25	**95**	**10.9%**
Annulus Flooding	84	23	197			**304**	**34.8%**
Outer Sheath	25		6			**31**	**3.5%**
End Fitting Leak / Failure			1	25	3	**29**	**3.3%**
Ancillary Equipment	37	8	71	6		**122**	**14.0%**
Global Pipe Defect	13	8	27	18	3	**69**	**7.9%**
Failure Mechanism Disputed	1			1		**2**	**0.2%**
Total	**173**	**149**	**371**	**147**	**34**	**874**	**100.0%**
%	**19.8%**	**17.0%**	**42.4%**	**16.8%**	**3.9%**	**100.0%**	

Table 4.6 Degradation Statistics, by Cause & Pipe Status, Grouped by Pipe Layer, Risers only (subset of Table 4.5)

Damage / Failure Cause	Number of cases, by status					Total	%
	Minor defect / damage	Shut-down (integrity concern)	Damaged (failure initiator)	Failed - leak	Failed - rupture		
Line Recovered Proactively - No significant damage / defect identified		38				**38**	**5.6%**
Carcass	1	7	30	9		**47**	**6.9%**
Internal Damage - Pigging			1			**1**	**0.1%**
Internal Pressure Sheath	4	30	6	29	3	**72**	**10.6%**
Armours	4	3	29	11	21	**68**	**10.0%**
Annulus Flooding	68	21	184			**273**	**40.2%**
Outer Sheath	14		5			**19**	**2.8%**
End Fitting Leak / Failure			1	8		**9**	**1.3%**
Ancillary Equipment	36	8	71	6		**121**	**17.8%**
Global Pipe Defect	2	5	14	7	1	**29**	**4.3%**
Failure Mechanism Disputed	1			1		**2**	**0.3%**
Total	**130**	**112**	**341**	**71**	**25**	**679**	**100.0%**
%	**19.1%**	**16.5%**	**50.2%**	**10.5%**	**3.7%**	**100.0%**	

Table 4.7 Degradation Statistics, by Cause & Pipe Status, Grouped by Pipe Layer, Flowlines & Jumpers only (subset of Table 4.5)

Damage / Failure Cause	Number of cases, by status					Total	%
	Minor defect / damage	Shut-down (integrity concern)	Damaged (failure initiator)	Failed - leak	Failed - rupture		
Line Recovered Proactively - No significant damage / defect identified		6				**6**	**3.1%**
Carcass		7		3		**10**	**5.1%**
Internal Damage - Pigging			1			**1**	**0.5%**
Internal Pressure Sheath	3	17	1	26		**47**	**24.1%**
Armours	1	2	1	19	4	**27**	**13.8%**
Annulus Flooding	16	2	13			**31**	**15.9%**
Outer Sheath	11		1			**12**	**6.2%**
End Fitting Leak / Failure				17	3	**20**	**10.3%**
Ancillary Equipment	1					**1**	**0.5%**
Global Pipe Defect	11	3	13	11	2	**40**	**20.5%**
Failure Mechanism Disputed						**0**	**0.0%**
Total	**43**	**37**	**30**	**76**	**9**	**195**	**100.0%**
%	**22.1%**	**19.0%**	**15.4%**	**39.0%**	**4.6%**	**100.0%**	

4.3.2 Focus on Damage & Failure

This section focusses on the three "status" criteria relating to *Damage* and *Failure* experience, which are deemed to be of most operational importance to users of flexible pipe. The three status criteria considered represent 552 cases in total.

The statistics relating to *Damage* & *Failure* are presented on the subsequent pages, as follows;

- Table 4.9, matrix of number of incidents, focussing on the three *Damage* and *Failure* categories, which results in 37 populated causes. Each individual populated cause is logically listed and grouped into those affecting either specific flexible pipe layers, or into "ancillary equipment" or "global pipe defect" groupings.
- Table 4.10, similar to Table 4.9, but the incident statistics of the 37 populated causes are now summed into 10 consolidated groupings based on the pipe layer or the alternative causal grouping.
- Table 4.11 presents the loss of containment (i.e. *Leak* and *Rupture*) incidents by failure mechanism. This includes a breakdown of the number of incidents to have occurred since 2011 and 2016 for each mechanism, allowing users to identify which LoC mechanisms have not been experienced in recent years.
- Figure 4.2, graphically presents the number of *Damage* and *Failure* incidents reported by the groupings in Table 4.10.

The three largest contributors for grouped *Damage* / *Leak* / *Rupture* causes are summarised in Table 4.8 below. As noted previously, more detailed descriptions, discussion, and mitigations relating to the most critical *Damage* and *Failure* causes are included in Section 4.4 of this report.

Table 4.8 Largest Contributors to Flexible Pipe Damage & Failure (by grouped causes)

<table>
<tr><th rowspan="2">Rank</th><th colspan="2">Damaged</th><th colspan="2">Failed – Leak</th><th colspan="2">Failed - Rupture</th></tr>
<tr><th>Riser</th><th>Flowline & Jumper</th><th>Riser</th><th>Flowline & Jumper</th><th>Riser</th><th>Flowline & Jumper</th></tr>
<tr><td>1</td><td>Annulus Flooding
184 cases, 54%</td><td rowspan="2">Annulus Flooding and Global Pipe Defects
(2 causes, 13 cases / 43% each)</td><td>Internal Pressure Sheath
29 cases, 41%</td><td>Internal Pressure Sheath
26 cases, 34%</td><td>Armours
21 cases, 84%</td><td>Armours
4 cases, 44%</td></tr>
<tr><td>2</td><td>Ancillary Equipment
71 cases, 21%</td><td>Armours
11 cases, 15%</td><td>Armours
19 cases, 25%</td><td>Internal Pressure Sheath
3 cases, 12%</td><td>End Fitting Leak / Failure
3 cases, 33%</td></tr>
<tr><td>3</td><td>Carcass
30 cases, 9%</td><td>Internal Damage - Pigging, Armours, Outer Sheath and Internal Pressure Sheath
(4 cases, 1 for each cause listed)</td><td>Carcass
9 cases, 13%</td><td>End Fitting Leak / Failure
17 cases, 22%</td><td>Global Pipe Defect
1 case, 4%</td><td>Global Pipe Defect
2 case, 22%</td></tr>
<tr><td>Total</td><td>285
(84% of Damaged Risers)</td><td>30
(100% of Damaged Flowlines & Jumpers)</td><td>49
(69% of Riser Leaks)</td><td>62
(82% of Flowline & Jumper Leaks)</td><td>25
(100% of Riser Ruptures)</td><td>9
(100% of Flowline & Jumper Ruptures)</td></tr>
</table>

Table 4.9 Damage & Failure Cases (only), by Cause & Pipe Status

Damage / Failure Cause	Number of cases, by status												Total No.	%
	Damaged (failure initiator)				Failed - Leak				Failed - Rupture					
	Riser		Flowline & Jumper		Riser		Flowline & Jumper		Riser		Flowline & Jumper			
	No.	%	No.	%	No.	%	No.	%	No.	%	No.	%		
Carcass Failure - Fatigue					1	1.4%							**1**	**0.2%**
Carcass Failure - Multilayer PVDF Collapse	24	7.0%			6	8.5%							**30**	**5.4%**
Carcass Failure - Tearing / Pullout	6	1.8%			2	2.8%	3	3.9%					**11**	**2.0%**
Internal Damage - Pigging	1	0.3%	1	3.3%									**2**	**0.4%**
Internal Pressure Sheath - Ageing	1	0.3%			6	8.5%	15	19.7%					**22**	**4.0%**
Internal Pressure Sheath - End Fitting Pull-out	3	0.9%			15	21.1%	4	5.3%					**22**	**4.0%**
Internal Pressure Sheath - Fatigue / Fracture / Microleaks	2	0.6%	1	3.3%	5	7.0%	4	5.3%					**12**	**2.2%**
Internal Pressure Sheath - Smooth Bore Liner Collapse					3	4.2%	3	3.9%	3	12.0%			**9**	**1.6%**
Tensile Armour Wire Breakage - in / close to end fitting					3	4.2%			1	4.0%			**4**	**0.7%**
Tensile Armour Wire Breakage - in main pipe section	12	3.5%			1	1.4%			8	32.0%			**21**	**3.8%**
Tensile Armours - Birdcaging	6	1.8%			7	9.9%	6	7.9%			1	11.1%	**20**	**3.6%**
Corrosion of Armours - Major / Catastrophic	4	1.2%	1	3.3%			13	17.1%	12	48.0%	3	33.3%	**33**	**6.0%**
Corrosion of Armours - Moderate	7	2.1%											**7**	**1.3%**
Annulus Flooding - Cause Unknown	89	26.1%	1	3.3%									**90**	**16.3%**
Annulus Flooding - Defective Annulus Vent System	4	1.2%											**4**	**0.7%**
Annulus Flooding - Outer Sheath Damage - Ageing / Fracture	4	1.2%											**4**	**0.7%**
Annulus Flooding - Outer Sheath Damage - Mechanical / Impact / Wear	87	25.5%	12	40.0%									**99**	**17.9%**
Outer Sheath Damage - Annulus NOT flooded - Mechanical / Impact / Wear	5	1.5%	1	3.3%									**6**	**1.1%**
End Fitting Leak / Failure	1	0.3%			8	11.3%	17	22.4%			3	33.3%	**29**	**5.3%**
Ancillary Equipment - Bend Stiffener - Connection / Interface	28	8.2%											**28**	**5.1%**
Ancillary Equipment - Bend Stiffener - 2 part failure	11	3.2%											**11**	**2.0%**
Ancillary Equipment - Bend Stiffener - other	2	0.6%			2	2.8%							**4**	**0.7%**
Ancillary Equipment - Hang-off Failure	1	0.3%											**1**	**0.2%**
Ancillary Equipment - Hold-down Failure (tethers / clamps / connections)	6	1.8%			1	1.4%							**7**	**1.3%**
Ancillary Equipment - Mid Water Arch	5	1.5%			1	1.4%							**6**	**1.1%**
Ancillary Equipment - Vent System Anomalies / Blockage	18	5.3%											**18**	**3.3%**
Ancillary Equipment - Other					2	2.8%							**2**	**0.4%**
Global pipe defect - Dropped Object / 3rd Party Interaction / Dragging	1	0.3%	2	6.7%			1	1.3%					**4**	**0.7%**
Global pipe Defect - Excess Tension									1	4.0%			**1**	**0.2%**
Global pipe Defect - Excess Torsion			2	6.7%			1	1.3%			1	11.1%	**4**	**0.7%**
Global pipe defect - Ovalisation			4	13.3%									**4**	**0.7%**
Global pipe defect - Overbend / Pressure Armour Unlock	3	0.9%	2	6.7%	6	8.5%	6	7.9%			1	11.1%	**18**	**3.3%**
Global pipe defect - Rough Bore Collapse			2	6.7%	1	1.4%							**3**	**0.5%**
Global pipe Defect - Upheaval Buckling			1	3.3%			3	3.9%					**4**	**0.7%**
Global pipe defect - Pipe Blockage (wax/hydrates/other)	9	2.6%											**9**	**1.6%**
Global Pipe Defect - Excess Marine Growth	1	0.3%											**1**	**0.2%**
Failure Mechanism Disputed					1	1.4%							**1**	**0.2%**
Total	**341**	**100%**	**30**	**100%**	**71**	**100%**	**76**	**100%**	**25**	**100%**	**9**	**100%**	**552**	**100.0%**
%	**61.8%**		**5.4%**		**12.9%**		**13.8%**		**4.5%**		**1.6%**		**100.0%**	

Table 4.10 Damage & Failure Cases (only), by Cause & Pipe Status, Grouped by Pipe Layer

Damage / Failure Cause	Number of cases, by status												Total No.	%
	Damaged (failure initiator)				Failed - Leak				Failed - Rupture					
	Riser		Flowline & Jumper		Riser		Flowline & Jumper		Riser		Flowline & Jumper			
	No.	%	No.	%	No.	%	No.	%	No.	%	No.	%		
Carcass	30	8.8%			9	12.7%	3	3.9%					42	7.6%
Internal Damage - Pigging	1	0.3%	1	3.3%									2	0.4%
Internal Pressure Sheath	6	1.8%	1	3.3%	29	40.8%	26	34.2%	3	12.0%			65	11.8%
Armours	29	8.5%	1	3.3%	11	15.5%	19	25.0%	21	84.0%	4	44.4%	85	15.4%
Annulus Flooding	184	54.0%	13	43.3%									197	35.7%
Outer Sheath	5	1.5%	1	3.3%									6	1.1%
End Fitting Leak / Failure	1	0.3%			8	11.3%	17	22.4%			3	33.3%	29	5.3%
Ancillary Equipment	71	20.8%			6	8.5%							77	13.9%
Global Pipe defect	14	4.1%	13	43.3%	7	9.9%	11	14.5%	1	4.0%	2	22.2%	48	8.7%
Failure Mechanism Disputed					1	1.4%							1	0.2%
Total	**341**	**100%**	**30**	**100%**	**71**	**100%**	**76**	**100%**	**25**	**100%**	**9**	**100%**	**552**	**100.0%**
%	**61.8%**		**5.4%**		**12.9%**		**13.8%**		**4.5%**		**1.6%**		**100%**	

Table 4.11 Loss of Containment Cases (only), by Cause & Date

Damage / Failure Cause	Loss of containment cases (Leaks + Ruptures)				Failed - leak				Failed - rupture			
	Total number of cases	Number of cases with dates	Number of cases since 01/07/11	Number of cases since 01/07/16	Total number of cases	Number of cases with dates	Number of cases since 01/07/11	Number of cases since 01/07/16	Total number of cases	Number of cases with dates	Number of cases since 01/07/11	Number of cases since 01/07/16
Carcass Failure - Fatigue	1	1			1	1						
Carcass Failure - Multilayer PVDF Collapse	6	6	1	1	6	6	1	1				
Carcass Failure - Tearing / Pullout	5	5	1		5	5	1					
Internal Pressure Sheath - Ageing	21	19	2		21	19	2					
Internal Pressure Sheath - End Fitting Pull-out	19	19	1		19	19	1					
Internal Pressure Sheath - Fatigue / Fracture / Microleaks	9	8	2		9	8	2					
Internal Pressure Sheath - Smooth Bore Liner Collapse	9	7			6	4			3	3		
Tensile Armour Wire Breakage - in / close to end fitting	4	1	1	1	3				1	1	1	1
Tensile Armour Wire Breakage - in main pipe section	9	9	9	4	1	1	1		8	8	8	4
Tensile Armours - Birdcaging	14	12	1		13	11	1		1	1		
Corrosion of Armours - Major / Catastrophic	28	24	15	8	13	9	4		15	15	11	8
End Fitting Leak / Failure	28	27	10	6	25	24	10	6	3	3		
Ancillary Equipment - Bend Stiffener - other	2	2			2	2						
Ancillary Equipment - Hold-down Failure (tethers / clamps / connections)	1				1							
Ancillary Equipment - Mid Water Arch	1	1			1	1						
Ancillary Equipment - Other	2	2			2	2						
Global pipe defect - Dropped Object / 3rd Party Interaction / Dragging	1	1	1	1	1	1	1	1				
Global pipe Defect - Excess Tension	1	1							1	1		
Global pipe Defect - Excess Torsion	2	2	1	1	1	1			1	1	1	1
Global pipe defect - Overbend / Pressure Armour Unlock	13	10	2	2	12	9	1	1	1	1	1	1
Global pipe defect - Rough Bore Collapse	1	1	1	1	1	1	1	1				
Global pipe Defect - Upheaval Buckling	3	3	2	1	3	3	2	1				
Failure Mechanism Disputed	1	1	1		1	1	1					
Total	**181**	**162**	**51**	**26**	**147**	**128**	**29**	**11**	**34**	**34**	**22**	**15**
% [1]	-	**89.5%**	**31.5%**	**16.0%**	-	**87.1%**	**22.7%**	**8.6%**	-	**100.0%**	**64.7%**	**44.1%**

Notes: 1. "Number of cases with dates" expressed as a percentage of "total number of cases". Number of cases since 01/07/11 and 01/07/16 expressed as a percentage of "number of cases with dates".

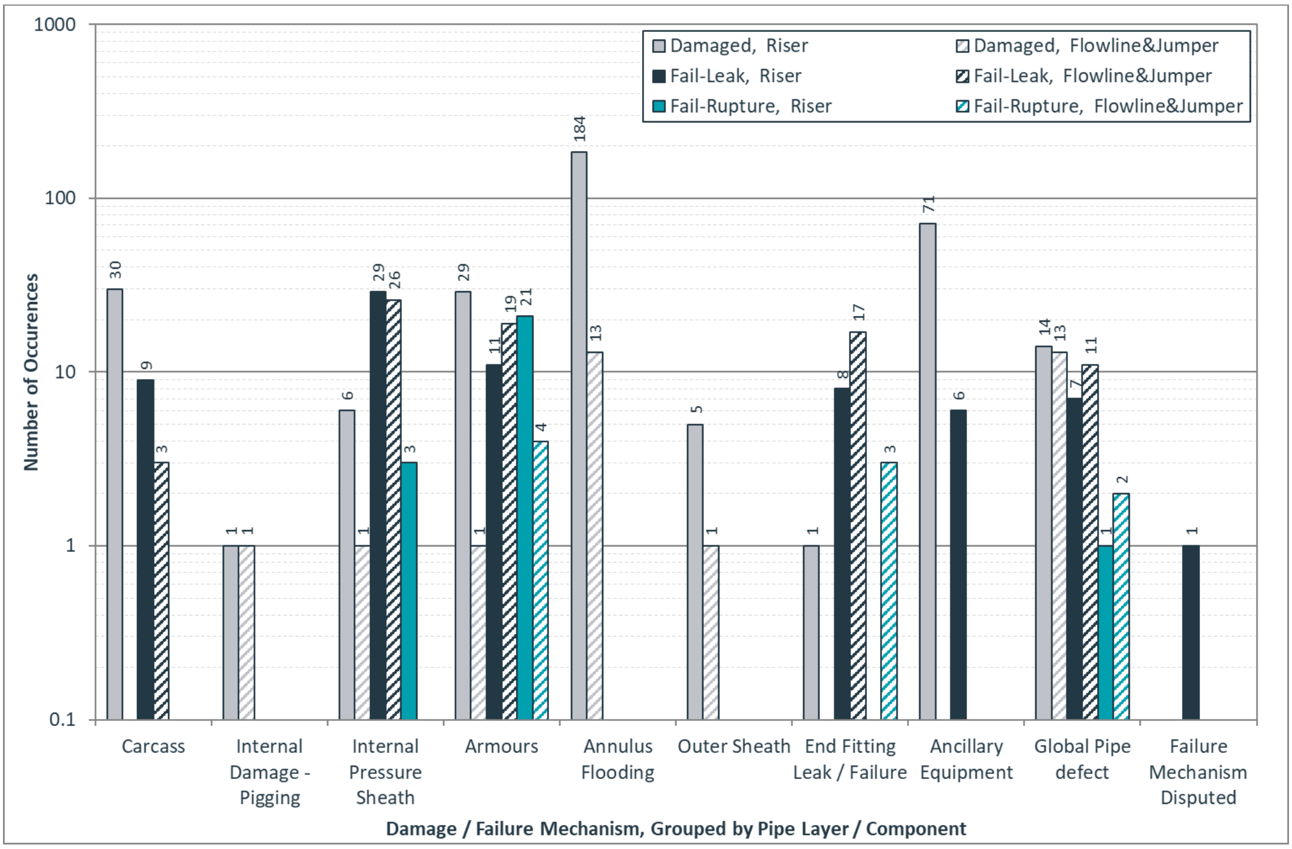


Figure 4.2 Damage & Failure Cases, Grouped by Pipe Layer / Component

4.3.3 Damage & Failure Timeline and Incident Rates

This section of the report focusses on the timing of *Damage* and *Failure* experience. Data relating to the timing of *Damage* and *Failure* incidents is not available for all *Damage* and *Failure* events. However, as detailed in Table 4.12 information relating to the timing of incidents is available for approximately 85% of all reported *Damage / Failure* incidents. **As such, any damage / failure rates are likely to be slightly underestimated through the timeline.** Artificially increasing all incident rates through all time periods with a generic factor could be used to "re-distribute" the incidents for which no date information is available, though this has the potential to significantly skew results so has not been applied.

It is important to note that the dates are attributed to when the damage / failure was identified. In many cases, particularly so for the *Damage* cases which are dominated by annulus flooding, the date of identification is likely to be well after the *Damage* event. As detailed in Section 4.1**, it is recommended that caution be applied in the use of this data to determine failure probabilities for a specific flexible pipe system**. **This must be carefully considered should the users of this report apply any information to provide input to support operational risk-based decisions**.

Table 4.12 Damage & Failure Experience and Timeline Datasets

Status	Riser			Flowline & Jumper		
	Number of Incidents	Incidents with Dates	% Incidents with Dates	Number of Incidents	Incidents with Dates	% Incidents with Dates
Damaged	341	284	83%	30	25	83%
Failed-Leak	71	60	85%	76	68	89%
Failed-Rupture	25	25	100%	9	9	100%
Total	**437**	**369**	**84%**	**115**	**102**	**89%**

In addition to the number of *Damage* and / or *Failure* incidents, in order to establish incident **rates** over specific time periods, the use of operational experience statistics are required which form the denominator of the incident rate calculation. These statistics are presented in Section 3.6 of this report.

Figure 4.3 and Figure 4.4 show the *Damage* and *Failure* timeline for flexible pipes for Risers and Flowlines & Jumpers respectively for all mechanisms. Some initial observations are as follows:

1. Riser *Rupture* events show a marked increase in the latest time period (10 separate events over the 5-year period), see Table 4.18 for a description of all reported *Rupture* events.
2. *Leak* incidents for Risers and Flowlines & Jumpers have dropped significantly in the latest 5-year period, and reported *Damage* incidents for Riser applications have reduced by approximately 42%.
3. As confirmed from Table 4.9, the overall number of reported *Leaks* for Riser and Flowlines & Jumpers are comparable (total 71 and 76 respectively).
4. Reported *Damage* and *Rupture* events are significantly more frequent for Risers compared to Flowlines & Jumpers. This finding is intuitive and further comparisons are presented of the respective incident rates (i.e. taking account of population) following Figure 4.3 and Figure 4.4.
5. The number of *Leak* incidents increased significantly for the time period of 1986 to 2001. This is largely the result of a number of incidents during the period relating to two specific *Failure* modes, as follows:
    a. PVDF end fitting pull-outs which typically occurred early in operations and have since been largely mitigated in design by the industry.
    b. PA-11 ageing experience, typically where PA-11 lines were operated in wet production use at excessively high temperatures. API technical report 17TR2, (Ref. [6]) resulted in improved understanding of the failure mechanism and a reduction in reported failures.
6. The large increase in *Damage* incidents from the period of 1996 onwards is primarily due to increased and improved testing, inspection, and / or monitoring, e.g. annulus testing, and integrity management awareness.

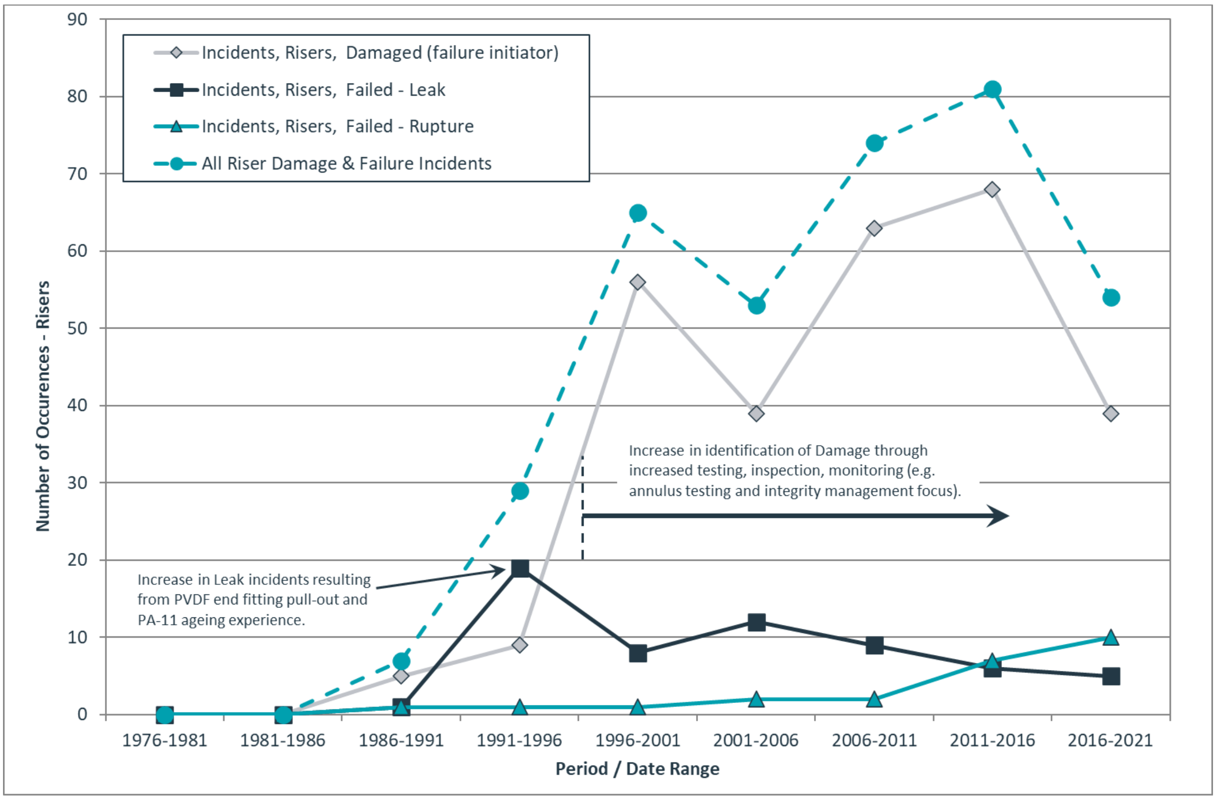


Figure 4.3 Damage & Failure Timeline – Risers

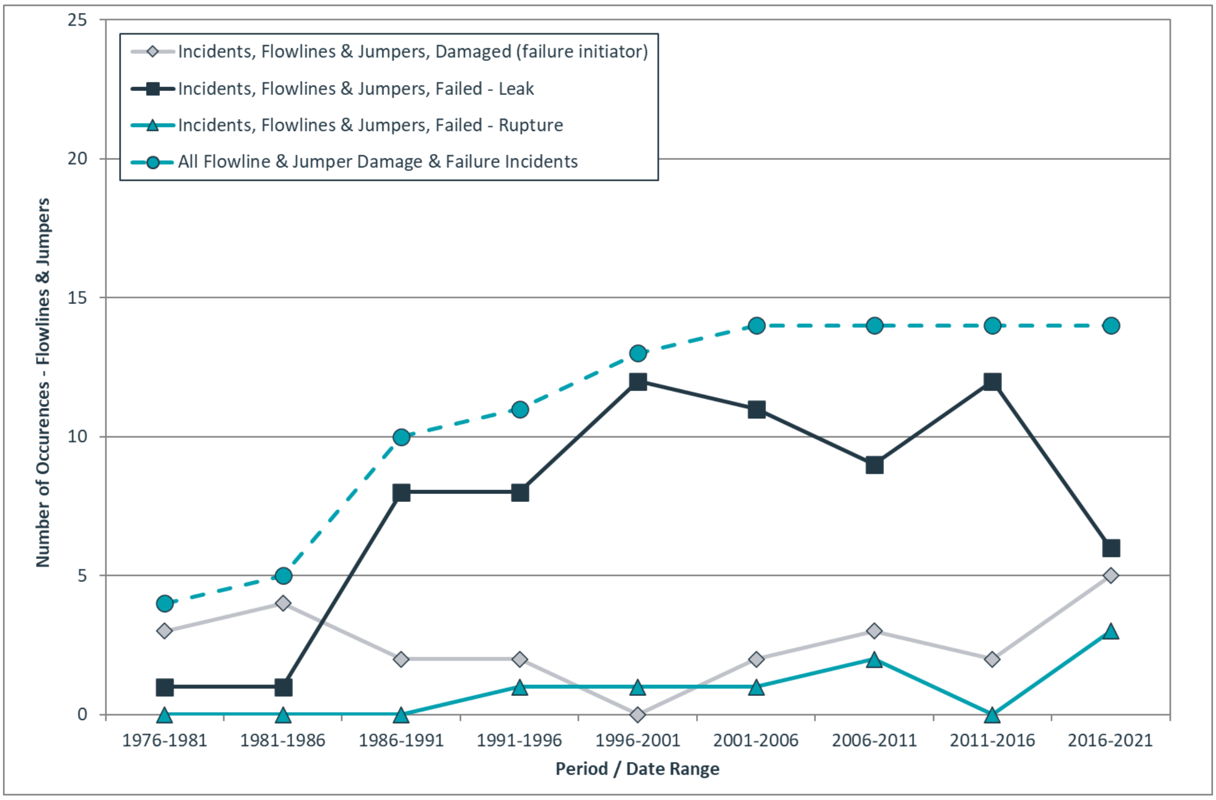


Figure 4.4 Damage & Failure Timeline – Flowlines & Jumpers

Table 4.14 lists and plots the calculated incident rates for cases of *Damage*, *Leak*, *Rupture*, and for all combined incidents, within the Sureflex database. The rates are presented in the units of incidents per pipe-year, and are presented separately for Risers and Flowlines & Jumpers. There is a marked increased in Riser *Rupture* rates in the most recent 5-year period, refer to Table 4.18 for a description of all reported *Rupture* events. However, *Damage* and *Failure* rates in all other categories continue to show a general downward trend since the 1990s.

A comparison of Riser vs Flowline & Jumper incident rates in Table 4.13 confirms that;

- significantly more *Damage* events are **identified** on Risers, which is likely the result of;
    - more onerous loading in service compared to Flowlines & Jumpers,
    - multiple ancillary equipment components compared to Flowlines & Jumpers,
    - increased accessibility to test / inspect compared to Flowlines & Jumpers which are often buried / trenched,
    - increased operator focus on Risers due to inherent safety threats i.e. proximity to personnel.
- the Riser *Leak* incident rate is tending towards that of Flowlines & Jumpers, and both are following a downward trend.
- there is no clear trend relating to *Ruptures*, due to the relatively low numbers of incidents (total of 24 Riser and 8 Flowline & Jumper events up to 2021, and 2 additional failures since 2021).

The resulting Sureflex JIP incident rates per pipe year relating to the period 2016 to 2021:

- Damaged Risers, 2.18E-03 Flowlines & Jumpers, 9.84E-05
- Failure – Leak Risers, 2.79E-04 Flowlines & Jumpers, 1.18E-04
- Failed – Rupture Risers, 5.58E-04 Flowlines & Jumpers, 5.91E-05
- **All *Damage & Failure*** Risers, 3.01E-03 Flowlines & Jumpers, 2.76E-04

It should be noted that the incident rates relating to this most recent period intuitively exclude failure mechanisms / events which are deemed to be "historical" (pre-2016) that have either been mitigated through design or updated operating procedures.

During the course of the JIP, members requested that alternative damage and failure incident rates be calculated as a sensitivity to those presented within this section. These alternative rates include incidents directly related to the flexible pipe system but exclude incidents caused by external factors (e.g. mishandling during installation, operating the pipe outside of its design envelope etc.). Refer to Appendix D for details of these alternative failure rate statistics.

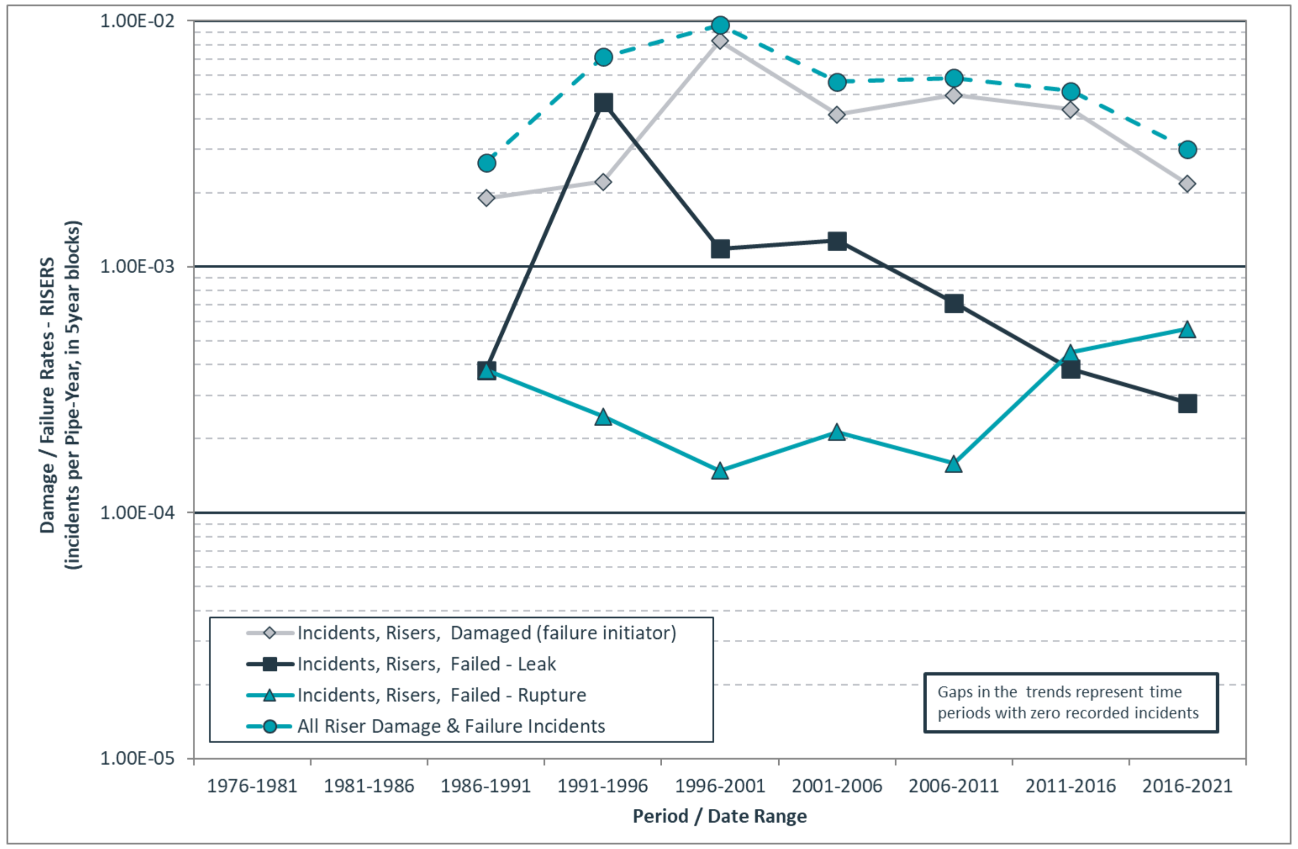
Table 4.13 Comparison of Riser Incident Rates as a Factor of Flowline & Jumper Rates

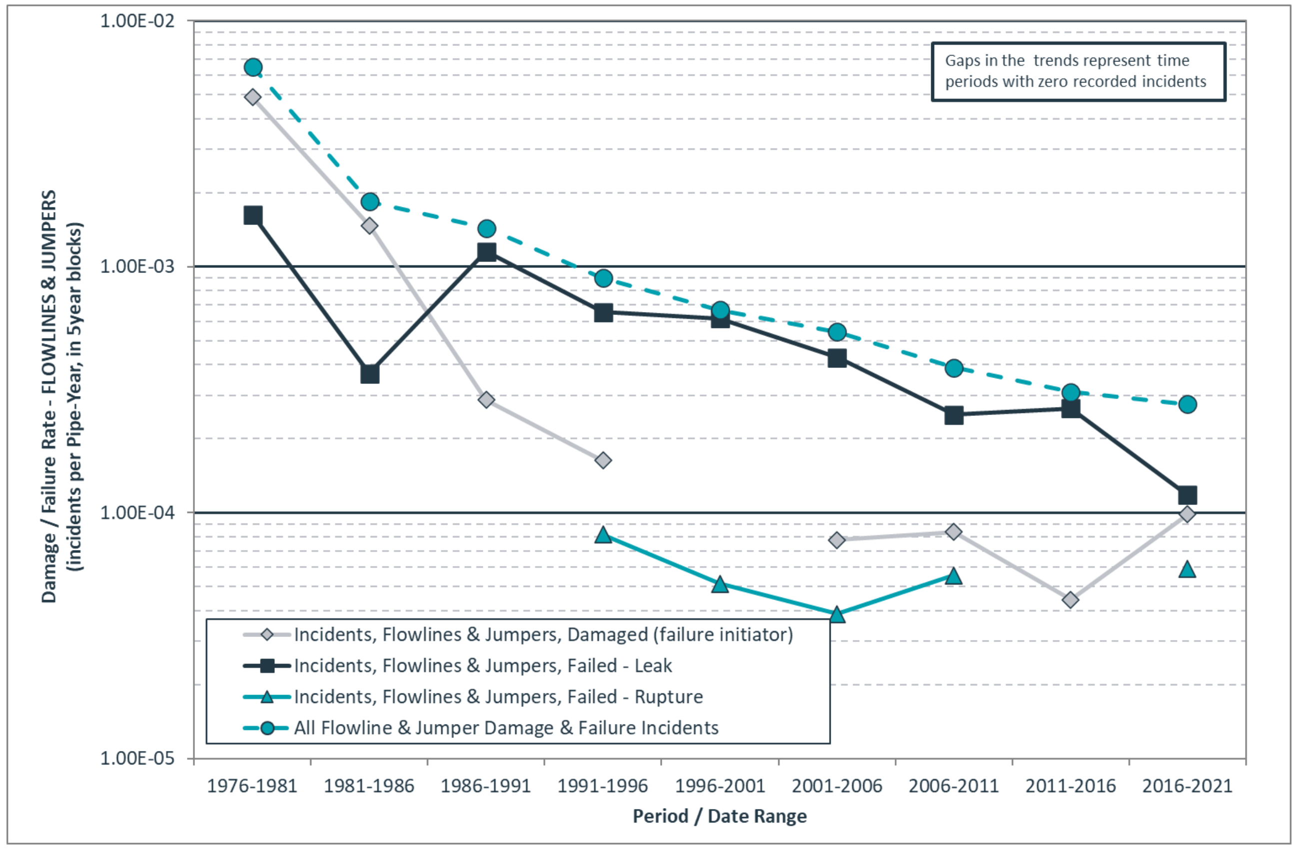
Period	Incident Rates; Riser Rate as Factor of the Flowline & Jumper Rate			
	Damaged	Failed - Leak	Failed - Rupture	ALL COMBINED
1986 – 1991	6.6	0.3		1.8
1991 – 1996	13.6	7.2	3.0	8.0
1996 – 2001		1.9	2.9	14.4
2001 – 2006	53.6	3.0	5.5	10.4
2006 – 2011	59.9	2.9	2.9	15.1
2011 – 2016	98.4	1.4		16.7
2016 – 2021	22.1	2.4	9.4	10.9
1976 – 2021	**34.5**	**2.5**	**8.5**	**10.4**

Note: 1. Factors are only presented for periods / cases where there is a calculated rate for both Risers and Jumper & Flowlines (see Table 4.14).

Table 4.14 Damage & Failure Incident Rates (Incidents per Pipe-Year)

Period	Damage / Failure Rate (incidents per pipe-year)							
	Risers				Flowlines & Jumpers			
	Damaged	Failed - Leak	Failed - Rupture	ALL COMBINED	Damaged	Failed - Leak	Failed - Rupture	ALL COMBINED
1976 – 1981					4.88E-03	1.63E-03		6.51E-03
1981 – 1986					1.47E-03	3.68E-04		1.84E-03
1986 – 1991	1.90E-03	3.80E-04	3.80E-04	2.66E-03	2.88E-04	1.15E-03		1.44E-03
1991 – 1996	2.22E-03	4.68E-03	2.46E-04	7.14E-03	1.63E-04	6.53E-04	8.16E-05	8.98E-04
1996 – 2001	8.29E-03	1.18E-03	1.48E-04	9.62E-03		6.17E-04	5.14E-05	6.68E-04
2001 – 2006	4.16E-03	1.28E-03	2.13E-04	5.65E-03	7.76E-05	4.27E-04	3.88E-05	5.43E-04
2006 – 2011	4.99E-03	7.13E-04	1.58E-04	5.86E-03	8.34E-05	2.50E-04	5.56E-05	3.89E-04
2011 – 2016	4.35E-03	3.84E-04	4.48E-04	5.18E-03	4.42E-05	2.65E-04		3.09E-04
2016 – 2021	2.18E-03	2.79E-04	5.58E-04	3.01E-03	9.84E-05	1.18E-04	5.91E-05	2.76E-04
1976 – 2021	**3.97E-03**	**8.54E-04**	**3.42E-04**	**5.17E-03**	**1.15E-04**	**3.40E-04**	**4.00E-05**	**4.96E-04**





4.3.4 Time to Failure

For *Failure* incidents (*Leaks* and *Ruptures*) for which the time in operation up to failure is known, the results are presented in Figure 4.5 (for all failure causes / mechanisms combined). Data is available for 79% of the *Leak* and 100% of the *Rupture* incidents. This shows that:

- For reported *Leak* events, a peak of 33 occurs within the first year, which relate to:
  - 1 event during Handling / Transportation,
  - 9 events during Installation,
  - 6 events during Commissioning,
  - 16 events during Operation,
  - 1 event where the life cycle phase is not defined.
- For *Leak* events, 87 occur within the first 10 year of operations (75% of cases where timeline can be calculated).
- For *Rupture* events, there is no clear trend relating to the time to failure. Further information is presented in Table 4.18 and Figure 4.17 relating to each *Rupture* event.
- No upward ("bath-tub") trend in late-life is indicated from the database at this time.

The time period to the reporting of *Damage* incidents is intentionally not presented as it is known that in a number of cases that *Damage* is reported significantly after the *Damage* was initiated / created, which could lead to non-conservative assessments.

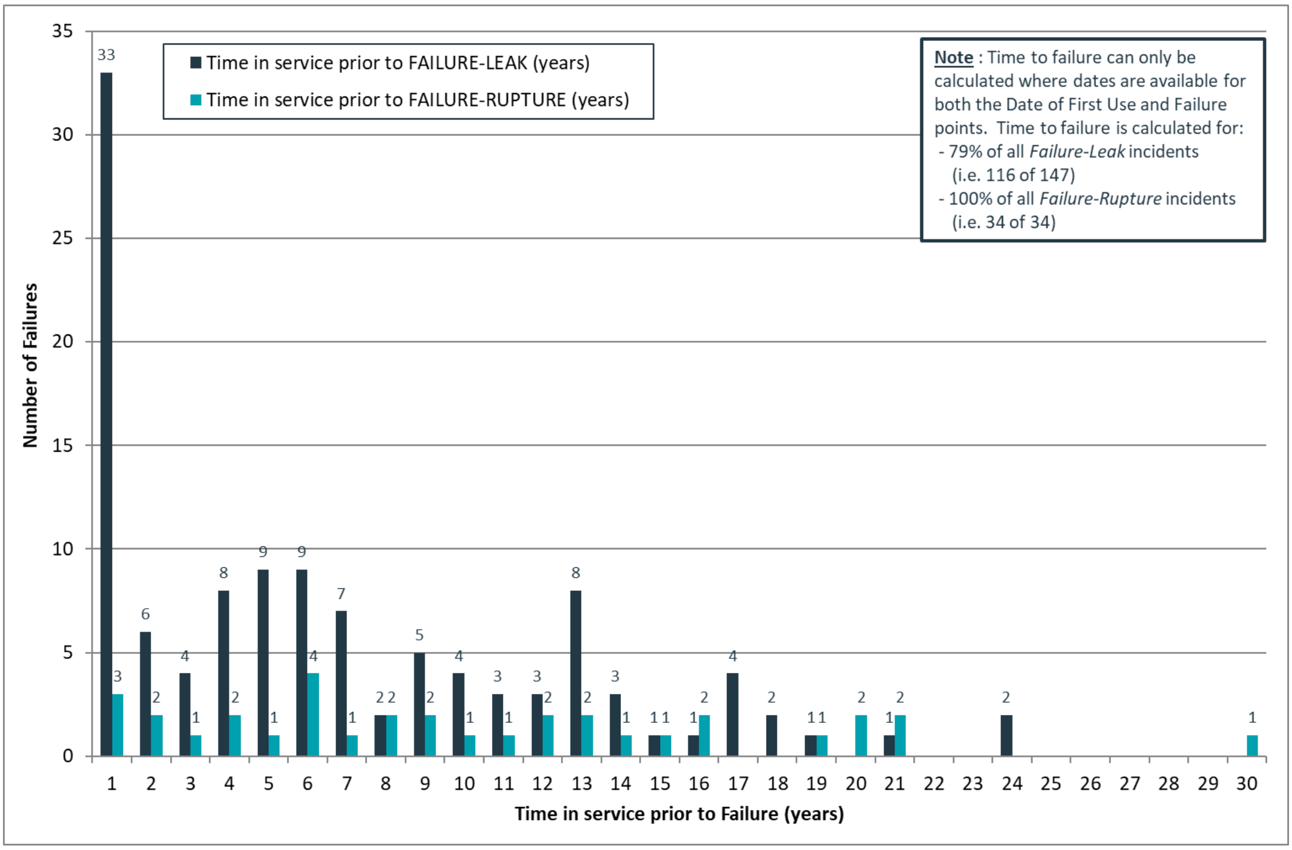


Figure 4.5 Time to Failure

4.3.5 Comparison Against Previous JIP Studies / Trends

This section of the report compares the trends of *Damage* & *Failure* events over previous JIP studies dating back to 2002 (whilst noting that the first JIP iteration in 2002 was limited to UK and Norwegian data).

Whilst the definitions relating to causes were refined in the 2016 JIP, Ref. [13] and the criteria relating to the pipe status developed further, it may be useful to compare the output of the previous studies with this JIP output. In order to perform this comparison, the dataset of 552 *Damage* & *Failure* cases from this JIP are consolidated into the same "mechanism groupings" that were utilised in the previous studies.

The total numbers of *Damage* & *Failure* incidents from each of the 4 JIP studies are noted in Table 4.15. Figure 4.6 and Figure 4.7 show the breakdown of incidents by the grouped *Damage* & *Failure* mechanisms, on a percentage basis of the study total, and based on the actual incident numbers respectively.

It should be noted that each individual JIP study includes all historic data that is reported during that phase and not just events that have occurred in the interim period, e.g. Aged Internal Sheath shows an increase in the 2021 data although none of those events occurred in the last 5-year period. In addition, retrospective analysis / re-categorisation / grouping of historical data has, in some instances, resulted in a reduction in the number of cases.

As noted previously, more detailed descriptions, discussion, and mitigations relating to the most critical *Damage* & *Failure* causes are included in Section 4.4 of this report. However, the key points of note from the comparison of failure mode trends:

Mechanisms showing a significant increase in incidents;

- *Sheath Damage / Annulus Flooding* continues to be the most prevalent *Damage* mechanism.
- *Ancillary Equipment* incidents have shown a consistent and significant increase over the 4 JIPs. Whilst industry codes (Ref. [2] & [5]) have been updated in recent years, ancillary equipment can be overlooked when considering riser system risks. In addition, in the case of ancillary equipment defects on a riser system, it is often the case that multiple pipes / risers are affected by the same mechanism.
- *Corrosion* incidents have shown a significant increase between the 2010 (1.9% of all damage and failure incidents) and 2021 studies (7.2%), as the flexible pipe inventory matures.
- Reported *End Fitting Leak* incidents continue to increase steadily in subsequent JIP phases.

Table 4.15 Total Number of Damage & Failure Incidents, per JIP phase

2002 JIP (Ref. [17, 18])	2010 JIP (Ref. [14, 15])	2016 JIP (Ref. [13])	Current (2021) JIP
106 (Note : UK & Norway only)	318 (Global)	394 (Global)	552 (Global)

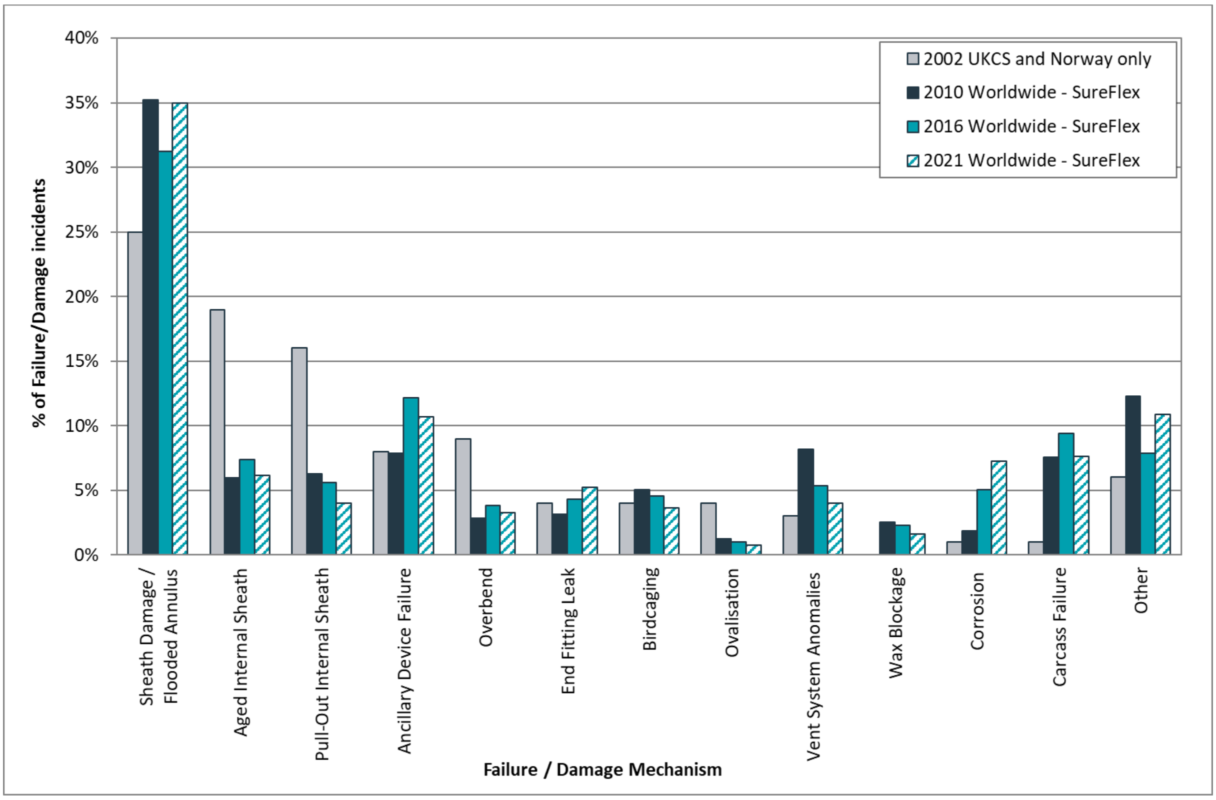


Figure 4.6 Flexible Pipe Failure/Damage Mechanisms, 2002/10/16/21 Comparison, % Split

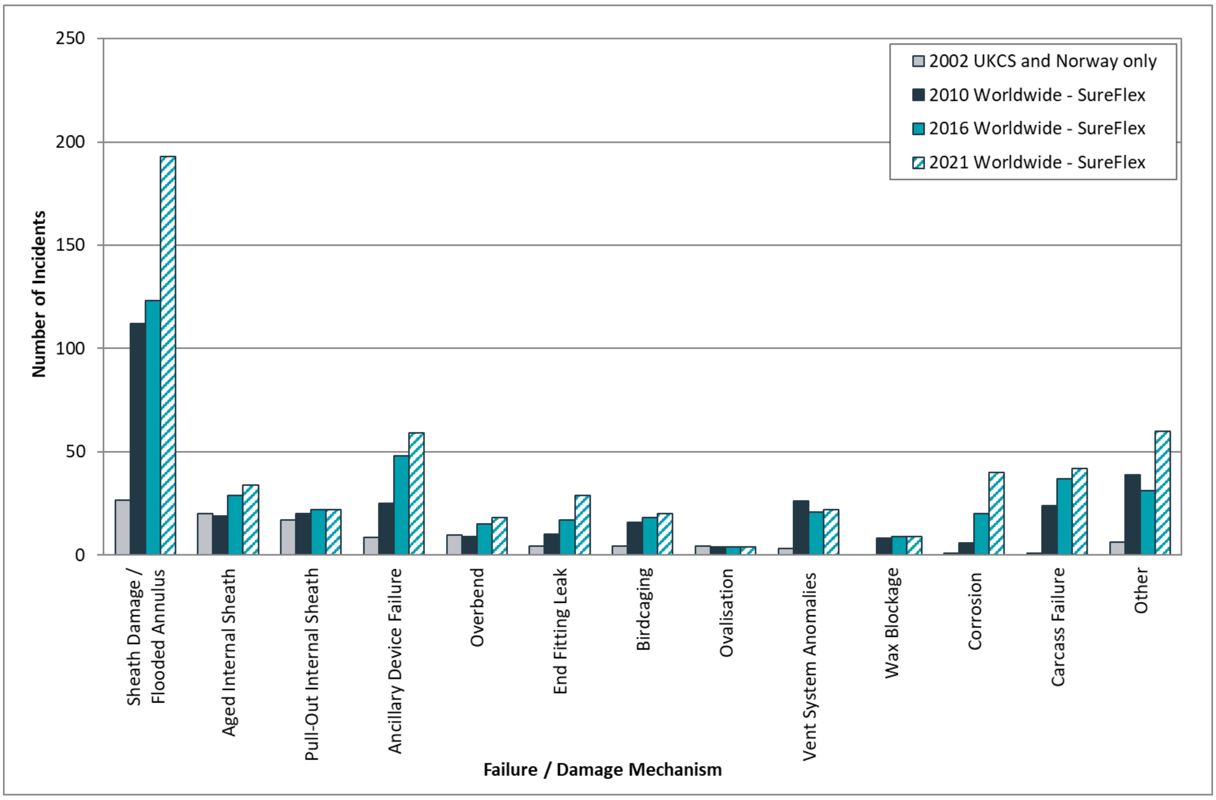


Figure 4.7 Flexible Pipe Failure/Damage Mechanisms, 2002/10/16/21 Comparison, No. Incidents

4.4 Description of Damage / Failure Experience & Applicable Mitigations

This section of the report discusses the main *Damage* and *Failure* mechanisms that contribute to the degradation of flexible pipe in operation. The mechanisms are described and any key mitigations discussed. Separate *Guidance Note* sub-sections are included where appropriate.

Earlier in this section of the report, Table 4.2 detailed experience defined over a number of individual failure mechanisms. For the purposes of the review / discussion in this section, the 830 reported incidents are grouped into 16 mechanisms as defined in Table 4.16 & Figure 4.8 / Figure 4.9 below. The following subsections of the report detail each of these grouped mechanisms.

In addition, Figure 4.10 and Figure 4.11 present further detail specifically relating to the *Damaged (failure initiator)*, *Failure – Leak* and *Failure – Rupture* events for Risers and Flowlines & Jumpers respectively. As well as a total incident count for each mechanism, incident counts since 2011 and 2016 are also included. The purpose of these plots is to help identify which mechanisms are prevalent / emerging (e.g. corrosion of armours or tensile armour wire breakage) and which are largely historical and have been mitigated through design (e.g. internal pressure sheath end fitting pull-out and carcass failures caused by multilayer PVDF collapse).

Table 4.16 Flexible Pipe Failure/Damage Mechanisms, % Breakdown for Discussion

Damage / Failure Cause	Riser or Flowline&Jumper	Minor defect / damage	Shut-down (integrity concern)	Damaged (failure initiator)	Failed - Leak	Failed - Rupture	Sub Total No.	Sub Total %	Total No.	Total %
Sheath Damage / Annulus Flooded	Riser	82	21	189			**292**	**35.2%**	**335**	**40.4%**
	Flowline&Jumper	27	2	14			**43**	**5.2%**		
Ancillary Equipment	Riser	16	5	53	6		**80**	**9.6%**	**80**	**9.6%**
	Flowline&Jumper						**0**	**0.0%**		
Corrosion of Armours	Riser	4	2	11		12	**29**	**3.5%**	**49**	**5.9%**
	Flowline&Jumper	1	2	1	13	3	**20**	**2.4%**		
Internal Pressure Sheath, Ageing	Riser		20	1	6		**27**	**3.3%**	**49**	**5.9%**
	Flowline&Jumper		7		15		**22**	**2.7%**		
Internal Pressure Sheath, End Fitting Pull-out	Riser		10	3	15		**28**	**3.4%**	**43**	**5.2%**
	Flowline&Jumper	2	9		4		**15**	**1.8%**		
Vent System Anomalies / Blockage	Riser	20	3	18			**41**	**4.9%**	**42**	**5.1%**
	Flowline&Jumper	1					**1**	**0.1%**		
Carcass Failure, Multilayer PVDF Collapse	Riser		7	24	6		**37**	**4.5%**	**39**	**4.7%**
	Flowline&Jumper		2				**2**	**0.2%**		
End Fitting Leak / Failure	Riser			1	8		**9**	**1.1%**	**29**	**3.5%**
	Flowline&Jumper				17	3	**20**	**2.4%**		
Tensile Armour Wire Breakage	Riser		1	12	4	9	**26**	**3.1%**	**26**	**3.1%**
	Flowline&Jumper						**0**	**0.0%**		
Tensile Armours - Birdcaging	Riser			6	7		**13**	**1.6%**	**20**	**2.4%**
	Flowline&Jumper				6	1	**7**	**0.8%**		
Overbend / Pressure Armour Unlock	Riser			3	6		**9**	**1.1%**	**18**	**2.2%**
	Flowline&Jumper			2	6	1	**9**	**1.1%**		
Carcass Failure, Tearing / Pullout	Riser	1		6	2		**9**	**1.1%**	**17**	**2.0%**
	Flowline&Jumper		5		3		**8**	**1.0%**		
Internal Pressure Sheath, Fatigue / Fracture / Microleaks	Riser	2		2	5		**9**	**1.1%**	**15**	**1.8%**
	Flowline&Jumper		1	1	4		**6**	**0.7%**		
Global pipe defect, Pipe Blockage (Wax / Hydrates / Other)	Riser			9			**9**	**1.1%**	**13**	**1.6%**
	Flowline&Jumper	3	1				**4**	**0.5%**		
Smooth Bore Liner Collapse	Riser	2			3	3	**8**	**1.0%**	**12**	**1.4%**
	Flowline&Jumper	1			3		**4**	**0.5%**		
Other	Riser	3	5	3	3	1	**15**	**1.8%**	**43**	**5.2%**
	Flowline&Jumper	8	2	12	5	1	**28**	**3.4%**		
Total		**173**	**105**	**371**	**147**	**34**	**830**	**100%**	**830**	**100%**
%		**20.8%**	**12.7%**	**44.7%**	**17.7%**	**4.1%**				

Notes: 1. The difference in the total number of occurrences between Table 4.2 and this table (Table 4.16) is a result of the certain cases being removed. Table 4.2 included 44 “incidents" where flexible pipe was pro-actively recovered, but for which there was no sign of damage / anomaly detected. Whilst these are valid in Table 4.2 where all integrity concerns are considered, they are not relevant here when addressing actual failure / damage experience.

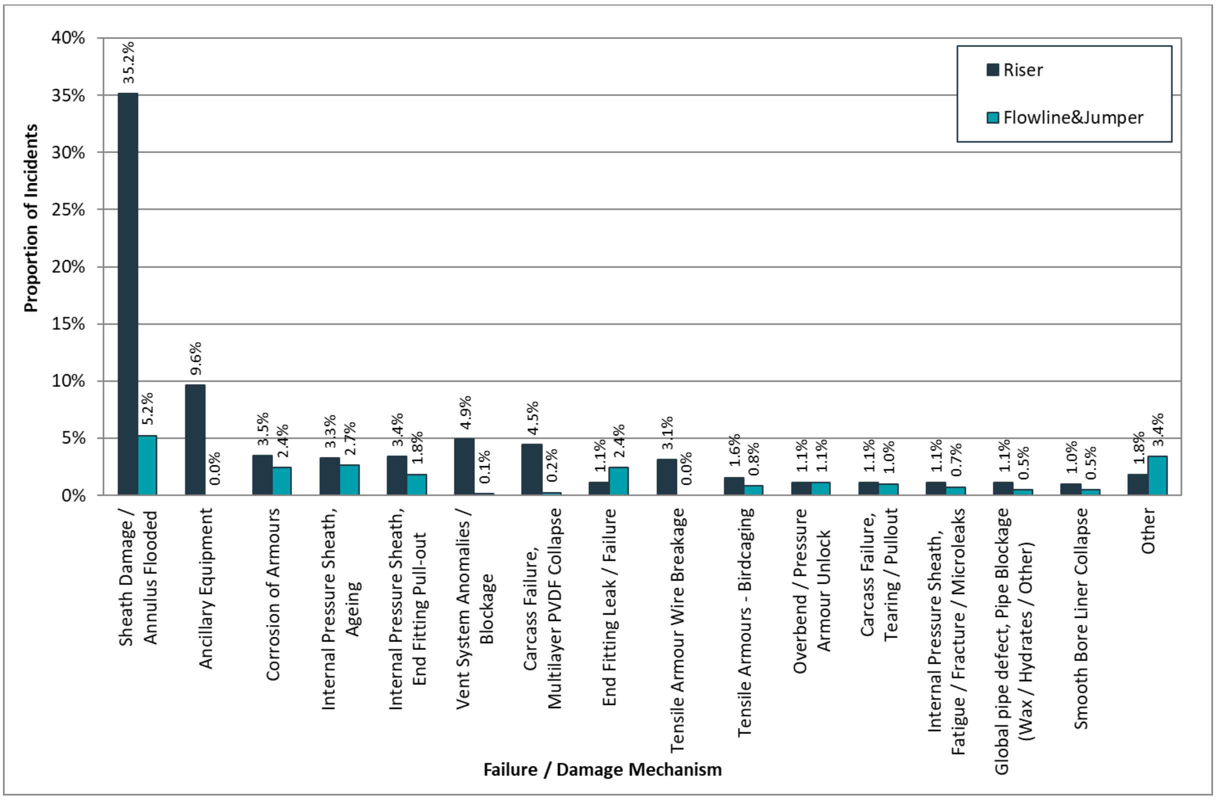


Figure 4.8 Flexible Pipe Failure/Damage Mechanisms, % Breakdown for Discussion

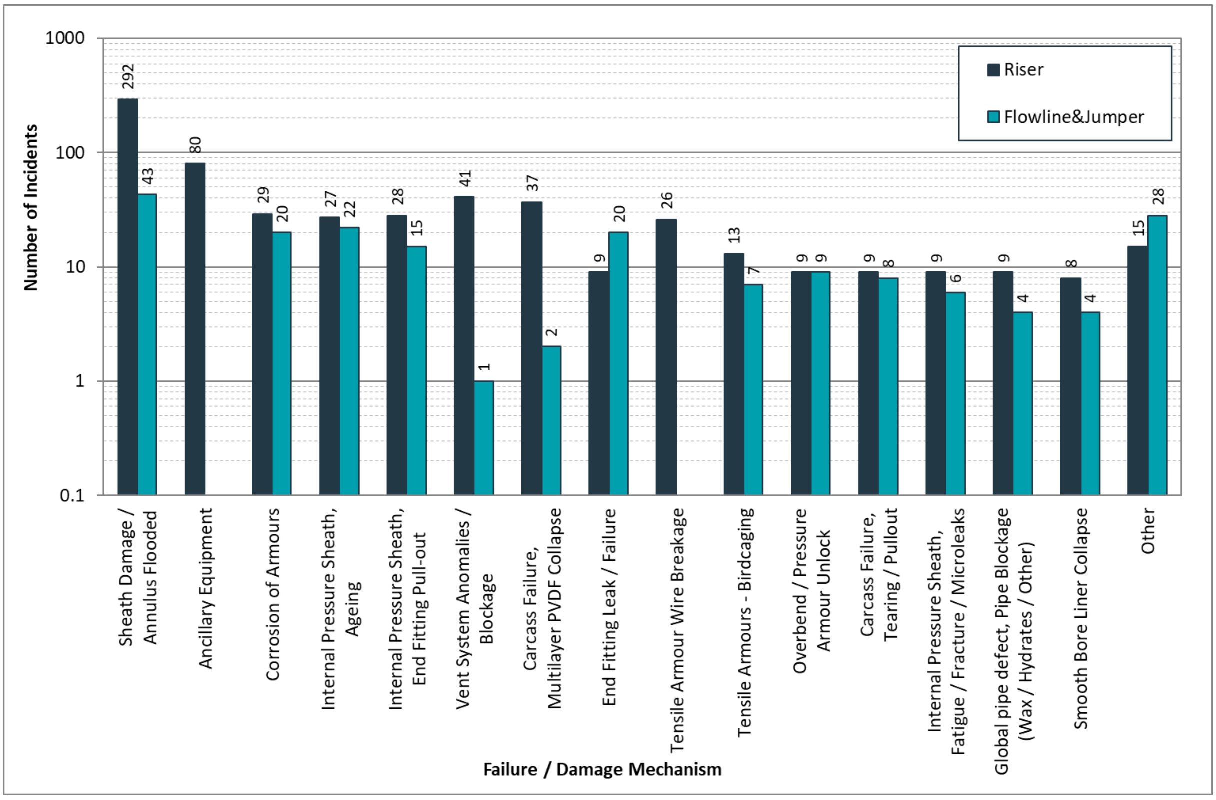


Figure 4.9 Flexible Pipe Failure/Damage Mechanisms, Breakdown for Discussion

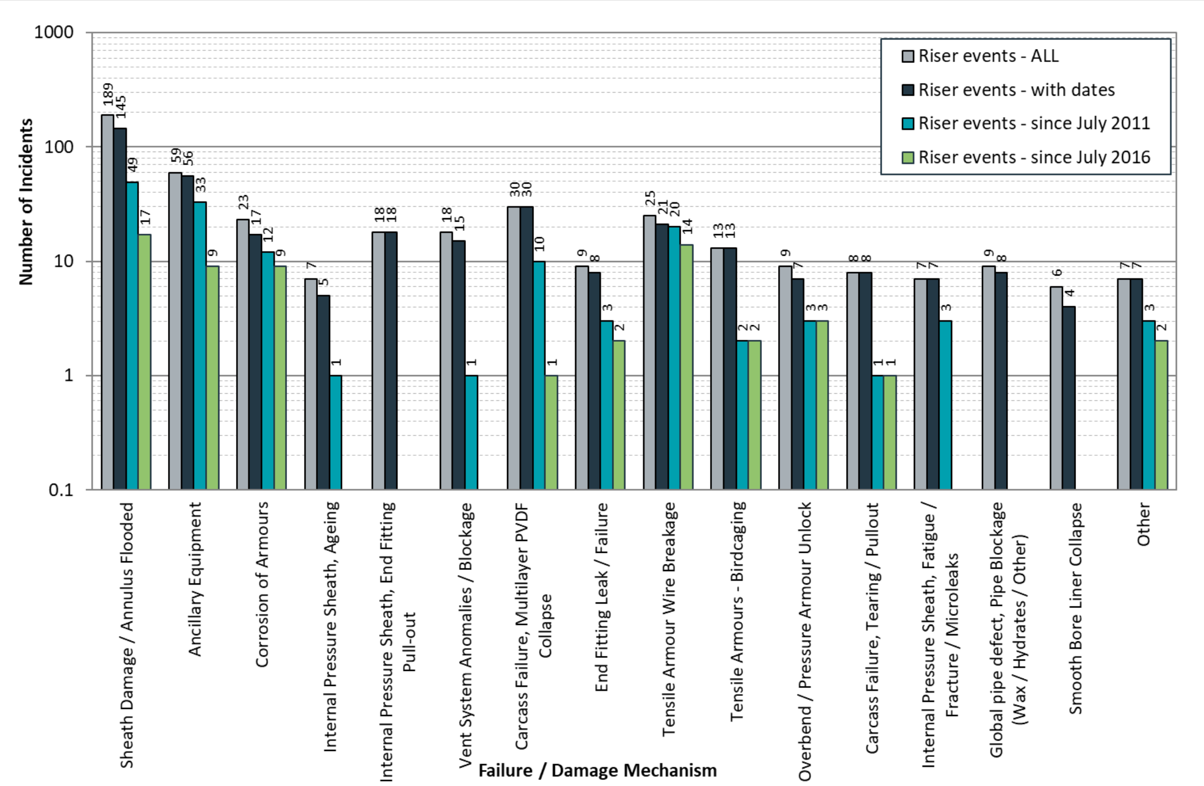


Figure 4.10 Failure/Damage Mechanisms, Breakdown for Discussion – Risers only

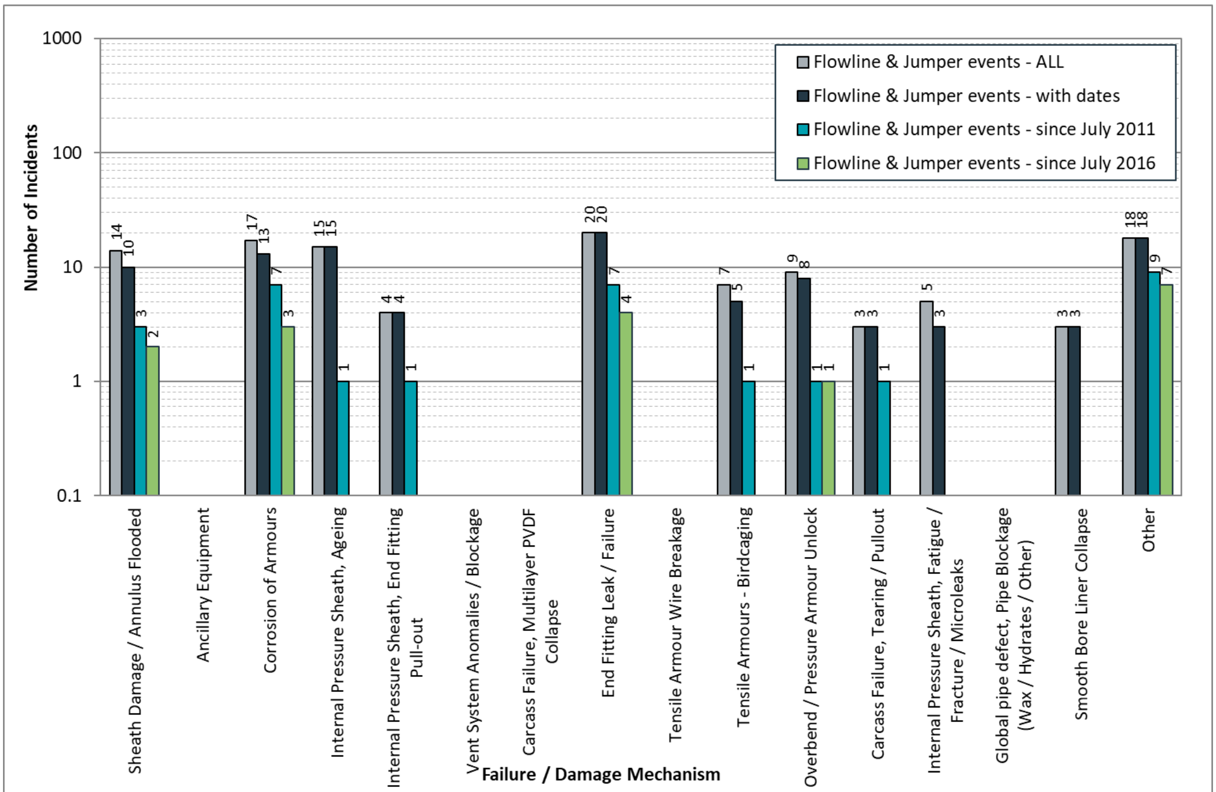


Figure 4.11 Failure/Damage Mechanisms, Breakdown for Discussion – Flowlines & Jumpers only

4.4.1 Sheath Damage / Annulus Flooded

Incidents relating to outer sheath damage and annulus flooding, through various sub-mechanisms, dominate the statistics and account for 40.4% of all flexible pipe *Damage* & *Failure* statistics. As noted previously the number of reported *Damage* incidents increased significantly from the late 1990s onwards, largely as a result of increased monitoring / testing which identified more pre-existing damage. The vast majority of experience in the category was classified as either *Damage*, or *Minor Defect / Damage*.

The ultimate consequence of annulus flooding is principally a *Failure* resulting from either reduction in armour capacity through corrosion or accelerated corrosion-fatigue. The number of cases where annulus flooding has been a contributor to *Failure* through one of these mechanisms are detailed in the specific failure mechanisms and are not "double counted" as annulus flooding *Damage*.

Of the 335 cases of sheath damage / annulus flooding, the event was reported to have occurred during:

- Installation, 47 cases,
- Commissioning, 8 cases,
- Operation, 250 cases,
- Handling / Transportation, 8 cases,
- Not given, 22 cases.

Guidance Note

In a number of cases damage that was identified during the operations phase may have occurred at an earlier life cycle phase, but was neither visually identified nor confirmed by annulus testing at that time. When the timeline of annulus flooding is not known, it is common for conservative assessments to be made regarding corrosion threats to flexible pipe. This provides a strong case for post-installation and ongoing operational verification of the annulus integrity.

The identification of annulus flooding is primarily the result of increased annulus monitoring, which is specific to riser applications where testing techniques utilise the (accessible) topsides vent ports to perform testing (292 of the 335 reported incidents, 87%, relate to dynamic risers). Annulus flooding is a particular concern for riser applications, where the corrosion-fatigue life is influenced by the annulus condition. In addition, if an outer sheath breach exists with seawater replenishment then oxygenated corrosion rates represent an increased threat, and have led to a limited number of Rupture events in recent years. For static flowline and jumper applications, flooding of the annulus does not provide a comparable fatigue threat. However, flooded annulus has led to high strength tape degradation / hydrolysis and reduced birdcaging resistance in some designs (also refer to Section 4.4.10 relating to birdcaging). Furthermore, annulus monitoring is not so straight-forward with damage identification typically relying on visual inspection, although techniques have been developed for subsea monitoring in the past 5 years. In flowline / jumper applications, where the contact risk is predominantly on the seabed (6 o'clock) position and / or the line may be trenched or buried to some degree, identification of small breaches is challenging. In this case, breach identification is commonly identified by bubbles (sometimes intermittently) coming from permeated gas exiting the annulus through small damage areas. Whilst it is dynamic risers that are most at risk from this threat due to fatigue and also corrosion in the oxygenated areas, it is considered possible that more degradation may become evident in other applications as a larger number of operational pipes reach longer service lives. Further information relating to the time to failure for corrosion-related failures is presented in Section 4.4.3.

Some pipe designs now utilise an additional external protective sheath, often over only local sections of the pipe, to increase the resistance to external wear. In recent years, some operators have elected to use this as the default for all *riser applications. In some circumstances, the corresponding increase in pipe stiffness gives an added benefit to the design. Additional mechanical protection (e.g. fabric / high strength tapes, thermal insulation etc.) may also be incorporated between the outer sheath and the secondary protective sheath to increase robustness. There is operational experience where significant damage occurred to a protective sheath during installation but annulus integrity was maintained.*

4.4.2 Ancillary Equipment

Flexible pipes, and specifically dynamic risers, rely on the specific use of ancillary equipment to maintain the pipe in the intended design configuration to ensure that all tensile, bending, and impact loading (both static and dynamic) remain within design allowables. In 2013, the first edition of the following documents providing specific industry guidance for ancillary equipment were published with the most recent editions issued in 2021:

- API Spec 17L1, Specification for Flexible Pipe Ancillary Equipment, Ref. [5].
- API RP 17L2, Recommended Practice for Flexible Pipe Ancillary Equipment, Ref. [2].

The database includes 80 incidents of flexible pipe degradation associated with ancillary equipment, with 53 of those relating to *Damage* experience. In a limited number of cases (6) these incidents resulted in pipe *Leaks*. While no cases are reported within this section relating to flexible pipe *Rupture* there is a known rupture incident that initiated with a flawed bend stiffener connection system design. This led to a breach in the outer sheath with subsequent corrosion-fatigue failure of the tensile armour wires resulting in pipe failure (see Table 4.18 for *Rupture* incident details). In addition, bend stiffener material properties have been identified as a contributory factor in other incidents where the tested polymer modulus / stiffness of all recovered risers from a single asset was significantly below the design minimum; *Rupture* (1) and *Damage* (1).

The breakdown of causes is shown in Table 4.17, below. The main ancillary equipment damage mechanisms are detailed in the following sub-sections.

Table 4.17 Ancillary Equipment Damage / Failure Mechanisms

Ancillary Equipment Damage / Failure Cause	Number of cases, by Status				Total No.	Total %
	Minor defect / damage	Shut-down (integrity concern)	Damaged (failure initiator)	Failed - Leak		
Bend Stiffener - Connection / Interface	7	2	28	0	**37**	**46.3%**
Bend Stiffener - 2 part failure	0	0	11	0	**11**	**13.8%**
Mid Water Arch	2	2	5	1	**10**	**12.5%**
Hold-down Failure (tethers / clamps / connections)	2	0	6	1	**9**	**11.3%**
Bend Stiffener - other	4	0	2	2	**8**	**10.0%**
Buoyancy Modules	1	1	0	0	**2**	**2.5%**
Other	0	0	0	2	**2**	**2.5%**
Hang-off Failure	0	0	1	0	**1**	**1.3%**
Totals	**16**	**5**	**53**	**6**	**80**	**100%**

Note: 1. All flexible pipe Damage / Failure experience associated with Ancillary Equipment relates to Risers; not associated with Flowlines & Jumpers.

4.4.2.1 Bend Stiffener Connector Mechanisms

Bend stiffener components are critical to the safe operation of a dynamic riser system. The bend stiffener ability to function relies on the integrity of the bend stiffener connector mechanism. Industry experience to date with bend stiffener connector mechanisms (37 cases) is summarised as follows:

- 18 cases, loss of the bend stiffener or degradation through either latch mechanism failure or bolt fatigue failure,
- 13 cases, severe corrosion of bend stiffener fastenings, in several cases requiring in-field remediation / replacement,
- 4 cases, bend stiffener tension support wires degradation, one of which resulted in bend stiffener loss, three resulted in wire change-out,
- 2 "other" cases.

<u>*Guidance Note*</u>

Bend stiffener connector failure experience tends to be the result of systematic failures relating to a combination of inadequate design, material issues, manufacturing / quality weaknesses, and inadequate interface management during the operational phase.

In addition to the operational experience of bend stiffener loss due to corrosion / failure of retaining tension wires, there is further operator experience where it became apparent in late life that the in-place tension wires were not fit for design life. In this instance, the operational change-out of the wires was extremely challenging.

Where there are unique / non-standard connector system configurations or are deployed in more onerous environments, adequate design review / challenge processes should be implemented for bend stiffener connection systems. It is recommended that a detailed qualification program is considered to ensure the mechanism is fit for purpose for the full life cycle of the intended design. This would normally include a series of load tests and pull-in trials for the combination of the riser, bend stiffener and latch mechanism to demonstrate confidence and repeatability. An assessment of the long-term integrity threats relating to materials selection and any hydraulic / mechanical based release mechanisms should also be completed.

In addition, care must be taken to ensure the loading around the bend stiffener interfaces are understood in detail. There is recent experience of a catastrophic in-service fatigue failure of a riser where concentrated contact loading led to localised fatigue damage in the connector section near the root of the bend stiffener (Ref. Section 4.4.9 on Fatigue).

4.4.2.2 Bend Stiffeners

Bend stiffeners are utilised to prevent the flexible pipe from overbending and to distribute the bending loads over a section of pipe as opposed to localised bending concentrated on the interface. There are a number of failure mechanisms that have been experienced in practice, as detailed below:

- 11 cases relating to damage / separation of the inner stiffener in a 2-part design
    - Loss of the inner bend stiffener in a 2-part design, which compromised the design (overbending) limits, caused external sheath damage, and in some cases initiated defects in the outer bend stiffener cone of sufficient size to cause large fractures / tears in the PU cone. Affected bend stiffeners were subject to replacement.
- 8 other incidents relating to bend stiffeners, reported as:
    - Cracking caused by out of specification polymer (1), disbondment (1), fatigue failure (2), gouges from water jetting (2), crack at tip (1), crushed / collapsed bend stiffener tip from installation (1).

The factors affecting in-service bend stiffener failure are generally not related to storm event mechanical overloading. Instead the experience noted above indicates a combination of inadequate design, material / installation issues and manufacturing / quality weaknesses.

Guidance Note

As noted in Section 4.4.2.1, bend stiffener components are critical to the safe operation of a dynamic riser system and should be incorporated into a risk based integrity management program.

Where there are unique / non-standard system configurations, adequate design review / challenge processes should be implemented. As noted above, guidance within API Spec 17L1 and API RP 17L2, Ref. [5] and [2] respectively, should be considered.

Operational experience to date indicates bend stiffener components have a good level of reliability. Nevertheless, due to the criticality and relatively high loads in service, it is essential that manufacturing procedures / checks to validate the bonding of the polyurethane to the metallic insert and that any defects in the PU are within qualified tolerance limits. In addition, it is common practice to provide external protection / packaging to the bend stiffener to mitigate damage during transport and pre-installation activities.

4.4.2.3 Mid Water Arches

There are 10 recorded cases of mid water arch (MWA) system damage / failures which have affected a greater number of risers. One of the reported incidents led to a pipe *Failure (Leak)*, some were subsequently condemned, and 1 was the subject of a sheath repair. These incidents included:

- An incident where a single tether failure led to multiple risers being dropped onto the seabed as the arch tilted (risers were held in place by gravity through a friction clamp). The failure was only identified during an annual inspection campaign. The risers were replaced on the repaired arch and successfully passed a pressure test prior to re-entering service.
- An incident where a rigid bridle failed due to fatigue, causing upending of the MWA (Ref. [74]). Although the risers were assessed to have exceeded their MBR limits, they subsequently passed structural integrity tests and returned to service following rectification of the MWA system.
- Two incidents on the same MWA in the space of 1 year, leading to a riser repair and 2 risers being condemned. In this shallow water case, the risers were physically connected to the top of the MWA as well as having additional hold-down tethers at the seabed end. The resulting MWA failure led to excessive loading and riser *Damage*.
- Other incidents relate to inadequate interface design between the clumpweights attached to the MWA tethers and the subsea structure. The MWA was not physically displaced in either of these cases, though subsea intervention was required to rectify.

Guidance Note

Similar to other ancillary equipment, MWA components should be included in a risk based integrity management program to monitor the threats relating to structural integrity, base movement, excessive motion, compartment flooding or other deviation from design intent.

4.4.2.4 Hold-down Failure

There are 9 incidents reported in the database relating to hold-down failure, one of which resulted in a *Failure (Leak)* of the flexible pipe. The causal factors generally relate to mechanical / design failure of the local interface equipment, although at least one incident relates to tether failure due to abrasion. In addition, there have been incidents where a hold-down system has failed on at least one riser, leading to the requirement for multiple change-outs. It should be noted that these additional (preventative) change-outs have not been captured within the database.

Guidance Note

Riser bases / anchors / tethers restrain the flexible riser in certain dynamic configurations and should be included in a risk based integrity management program to monitor the threats relating to base movement, failure, clashing, material degradation, or other deviation from design intent. The riser base loads may be sensitive to the host offset location / direction and the as-installed position / excursions should be checked against the design installation tolerances.

4.4.2.5 Buoyancy Modules

The 2 reported incidents of "cascading" buoyancy modules relate to cases where the titanium bands within the buoyancy module clamps could not withstand the diameter variation associated with the crushing of the insulation layers on the pipe. Following several years operation, the buoyancy modules grouped into large clusters leading to localised bending. One riser was condemned due to integrity concerns and the other was assessed to be fit for continued service following re-configuration of the buoyancy modules.

Guidance Note

*There is experience of minor impact damage and partial slippage of individual buoyancy modules within the industry, which is **not** captured within the incident database. In the case of minor impact damage, there is experience of testing recovered buoyancy modules which has confirmed residual buoyancy to be within original design tolerances.*

Partial slippage of individual buoyancy modules is not normally a major concern, as long as a series of adjacent modules do not "cascade" and move together. In most cases, the slippage of individual (isolated) modules is thought to be caused by either incorrect / inadequate torquing of a clamp during installation and / or individual clamp failure.

4.4.3 Corrosion of Armours

The annulus environment of a flexible pipe can be corrosive due to CO_2 and / or H_2S in the presence of water vapour permeation through the internal pressure sheath, or from seawater ingress, in the confined annulus between the sheaths. Due to the confined and restricted nature of the flexible pipe annulus, modelling of corrosion rates can be problematic especially in oxygenated environments, and very difficult to verify in service.

In this phase of the JIP, two additional emergent and previously unreported corrosion mechanisms that have resulted in multiple *Rupture* and *Damage* events, as follows;

- Moist atmospheric gases entering through open vent systems causing localised corrosion at the end fitting particularly where the riser has been operated intermittently (i.e. "breathing").
- Stress corrosion cracking (SCC) due to significantly elevated CO_2 partial pressures.

The *Damage* / *Failure* database includes 49 incidents relating to corrosion experience of armour wires, which are summarised as follows:

- 15 incidents of *Failure* by *Rupture* which can be categorised as:
    - 4 cases of general corrosion of armour wires in the oxygenated splashzone.
    - 4 cases caused by SCC on the tensile armour wires (typically most onerous at maximum depth / pressure).
    - 3 cases of cracking / corrosion (HIC / SSC) mechanism in un-reinforced 55° armour designs,

i.e. with no dedicated pressure armour layer. Further discussion of this mechanism is provided in the discussion of *Leak* incidents below.
    - 2 cases of corrosion of tensile armour wires close to the end fitting as a result of an open / breathing vent system drawing in moisture and oxygen.
    - 1 case where high strength sweet armour wires operated in a sour environment (high CO_2).
    - 1 case of a topside jumper operations not adhering to the operation and maintenance manual guidelines.

  Further information relating to all *Rupture* incidents are summarised in Section 4.5 of this report.
- 13 incidents of *Failure* by *Leak*:
    - 11 incidents of cracking / corrosion (HIC / SSC) mechanisms resulting in *Failure* by *Leak* in un-reinforced 55° armour designs i.e. with no dedicated pressure armour layer. These incidents relate to flowlines / jumper applications and utilise high strength (sweet) armours. These pipe designs typically have a higher armour wire utilisation which may make them more susceptible to certain stress-driven corrosion mechanisms. A combination of factors are thought to have caused these failures, as follows:
        - Low level H_2S considered as an aggravating factor on sweet service armours.
        - Overprotection by CP systems.
        - Local hardening as a result of impact damage.
        - Partial flooding of the annuli leading to seawater / gas interfaces around the 3 / 9 o'clock positions resulting in repeated failures on the same wire at consecutive "wraps".
    - 1 incident relating to severe localised pressure armour corrosion.
    - 1 "undefined" corrosion incident from 1993 resulting in *Failure* by *Leak*.
- 12 cases of *Damage*:
    - 6 cases where outer sheath damage led to varying degrees of observed armour wire corrosion.
    - 2 cases where risers were reterminated after an assessment concluded the risers were at high risk of *Failure* (following a *Rupture* incident of another riser at the same asset). All risers were connected to an open / breathing vent system. Upon retermination, corrosion and wire breakages were observed in the damaged section.
    - 2 cases where suspected backflow from atmosphere into the riser annuli prompted further inspection that identified multiple tensile armour wire breaks.
    - 2 cases with SCC attributed damage that was identified following pipe recovery / dissection. Prior to recovery, the risk of *Failure* of these pipes had been assessed to be high following an SCC attributed *Rupture* of another riser at the same asset.
- 5 cases where the pipes have *a Minor defect / damage*:
    - 1 case of suspected corrosion following inspection.
    - 4 cases of suspected corrosion due to increasing H_2S levels in production fluid.
- 4 incidents classed as *Shut-down - Integrity Concern*:
    - 2 cases of subsea flexible jumpers replaced due to doubts over sour service capability.
    - 2 cases of moderate corrosion identified on tensile armour wires.

The database includes a total of 24 corrosion related *Failure* events for which the time in service to failure can be established (12 *Ruptures* which occurred in Riser applications and 3 *Rupture* and 9 *Leaks* which occurred in Flowline & Jumper applications).

Figure 4.12 presents a histogram of the time in service to failure for these corrosion incidents. Additionally, the reported primary corrosion mechanisms are grouped and presented in a timeline in Figure 4.13. The plots show that there is a high variability in the time to failure for the range of corrosion mechanisms. This is likely due to the wide range of variables and factors affecting individual mechanisms, which prompted the Corrosion Monitoring JIP (see Section 8.10). A further factor is that for some corrosion mechanisms, additional failures would have occurred had it not been for proactive shutdown of similarly affected pipes.

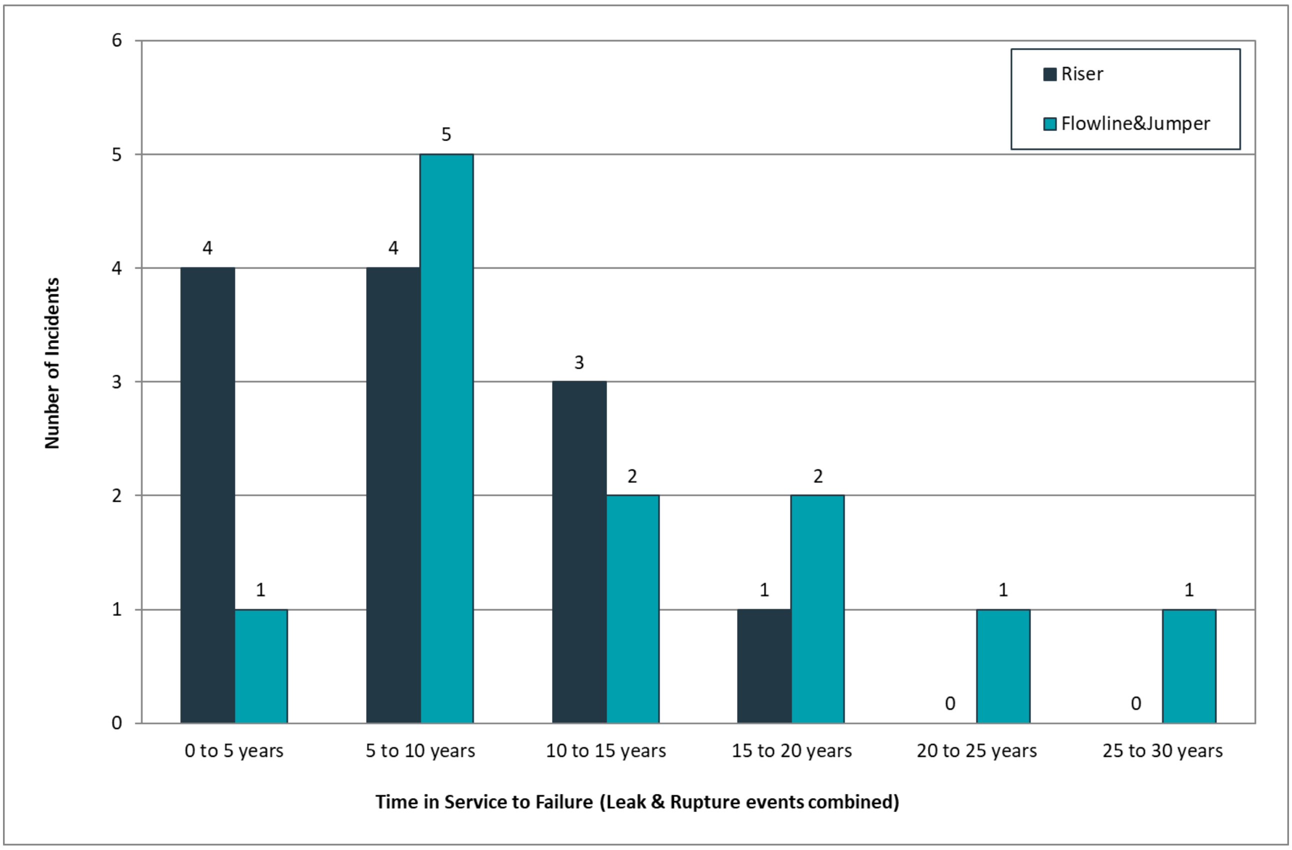


Figure 4.12 Time in Service to Failure for Corrosion Incidents

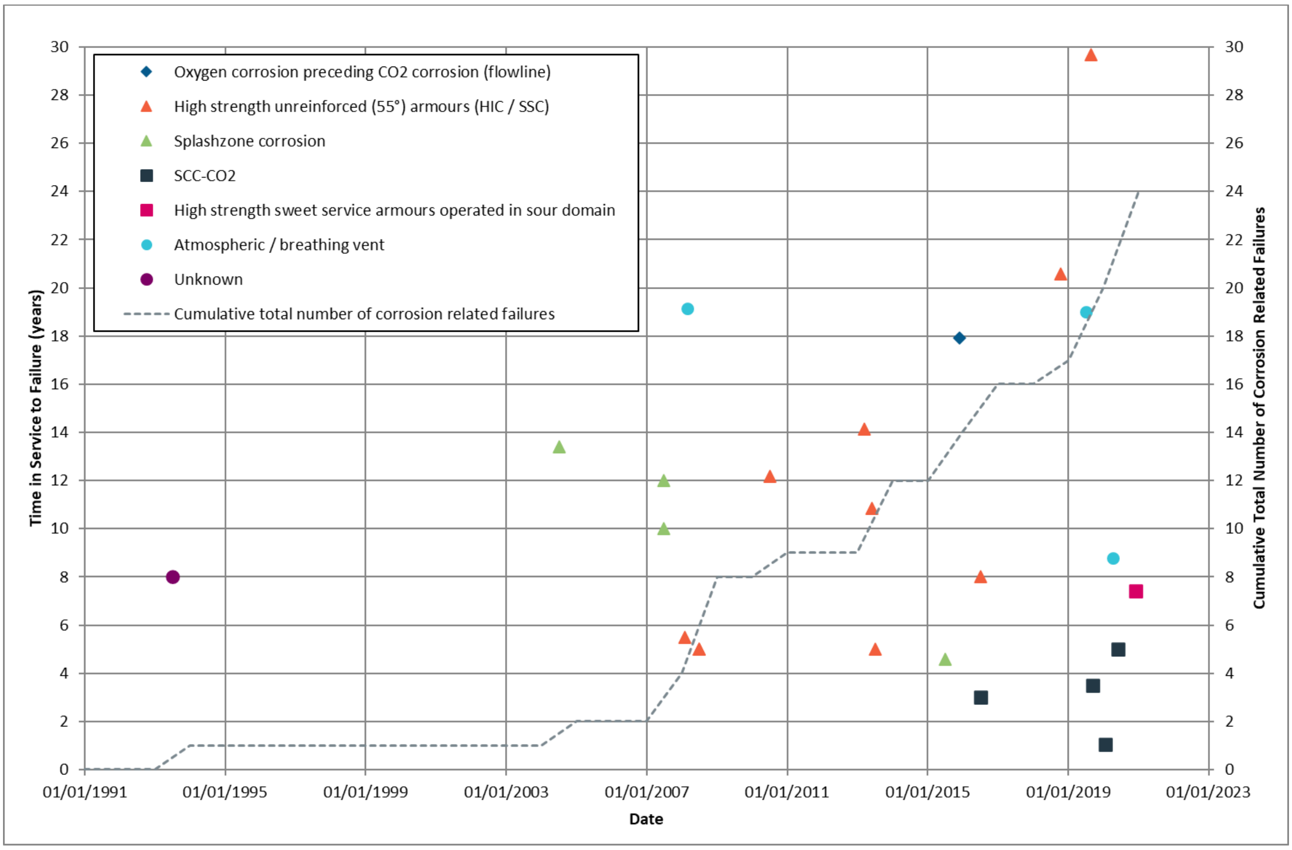


Figure 4.13 Timeline and Time in Service to Failure for Corrosion Mechanisms

Note: 1. There are 2off failures represented by a single point in 2008 (5years service to failure, for 55° armours HIC/SSC mechanism).

Guidance Note

*Industry experience shows that the corrosion rates witnessed in service are **generally** low, unless there is an open oxygenated breach in the outer sheath / breathing vent and / or accelerated degradation due to contact / abrasion or CP shielding. Reference should also be made to Section 4.4.9.3 relating to guidance on surface profile / pitting and the implications on corrosion-fatigue life.*

The result of corrosion assessment predictions for confined flexible pipe annuli, Ref. [29], indicates that the long term corrosion rate for a flexible pipe annulus away from the sheath breach is approximately 15µm/yr and then, rapidly decreases within the first few months of exposure to 0.15µm/yr. The initial corrosion rate decreases due to an increase in pH and iron ion saturation combined with the build-up of corrosion products on the exposed wire surfaces. It should be noted that wire corrosion mechanisms and rates remain a topic of ongoing industry research and are intended to be captured in the API 17J / B updates, refer to Section 8.2 and 8.10 for further information. There is previous specific experience of corrosion rates of ~1mm/year on all surfaces of a wire in the case of a heated / insulated bend stiffener location, which was verified by inspection upon recovery. In deepwater applications where the annulus pressure is high and in the presence of water, supercritical CO_2 levels are an emergent threat that is subject to ongoing research, see Section 8.3 for details.

*At outer sheath breaches in the presence of oxygenated seawater renewal and / or with cathodic protection shielding or in the cases of breathing vent systems open to atmosphere, high corrosion rates can be experienced and have led to failures (*Ruptures*) and significant damage. Therefore, routine annulus monitoring to detect flooding and* *appropriately designed and maintained vent systems to prevent atmospheric backflow should be implemented.*

One damage event, Ref. [25], relates to annulus flooding, inspection and repair of a riser which exhibited high corrosion rates and 15 failed armour wires over a period of ~4 years. In addition, there is similar experience on other assets where high corrosion rates were found locally within the vicinity of the outer sheath breaches, and very low corrosion rates a short distance from the sheath breaches. In these cases, damage has normally been confirmed through proactive integrity management programs which have identified the failure initiator (splash zone sheath breach) early on. In most of these cases where corrosion had initiated, the damaged risers have been recovered relatively soon (within 5 years) of the damage being verified, or a repair completed. If they had continued in extended service, it is likely that some of them would have failed. This experience is validated through wider industry experience and reinforces the recommendation to clamp / repair, or replace risers with outer sheath breaches, particularly where a sheath breach exists close to any oxygenated environment and/or any fatigue hotspot.

In an incident reported during the previous iteration of the JIP, severe localised pressure armour corrosion was identified on a subsea flowline leading to a leak. Whilst the tensile armour wires were also subject to significant corrosion, it was concluded that initial pressure armour oxygen corrosion followed by subsequent CO_2 driven corrosion was the root cause.

4.4.4 Internal Pressure Sheath, Ageing

The internal pressure sheath ageing experience typically relates to the degradation of Polyamide (PA) pressure sheaths, which is caused by hydrolysis and embrittlement of the polymer in the presence of water and aggressive environments at elevated temperatures. There are 49 reported incidents within the database relating to this degradation mechanism, 47 of which have dates associated with them. Figure 4.14 shows the timeline of this failure mechanism, which confirms the largest number of damage and failure incidents occurred in the period 1996 to 2001. The lessons learned from the experience through this period were used by the industry to develop API 17TR2, Ref. [6], which includes a degradation model to predict an initial acceptance criteria based on the polymer corrected inherent viscosity (also refer to Section 8.5).

The evidence gathered in this JIP indicates that in the last 15 years there have been five *Leak* failures (two Riser and three Flowline) relating to this failure mechanism, and an additional 21 flexible pipes (14 Dynamic Risers, 7 Flowlines) which have been shut-down due to integrity concerns during this period. Of these, four were 6 years old, one was 10 years old and the remaining 16 were in the 15 to 20 year old range. The reported reasons for these shut-downs are the result of degradation calculations (API 17TR2) and / or the results of polymer coupon analysis. In the last 5 year period, there have been no *Failures* reported for this mechanism.

<u>*Guidance Note*</u>

For lines that have failed by this mechanism, the available data indicates that the operating temperatures have either been in excess of the stated design temperature, and / or that the design temperature pre-dates the learnings from API 17TR2, Ref. [6]. For historical failures (pre 2000) whilst there is limited reported operational data, there is anecdotal evidence that the pipe temperature limits were routinely exceeded. This is validated through the experience noted in Appendix F of API 17TR2 where failures typically occurred when operating temperatures were in region of 100°C. Further information is provided in Section 8.5.

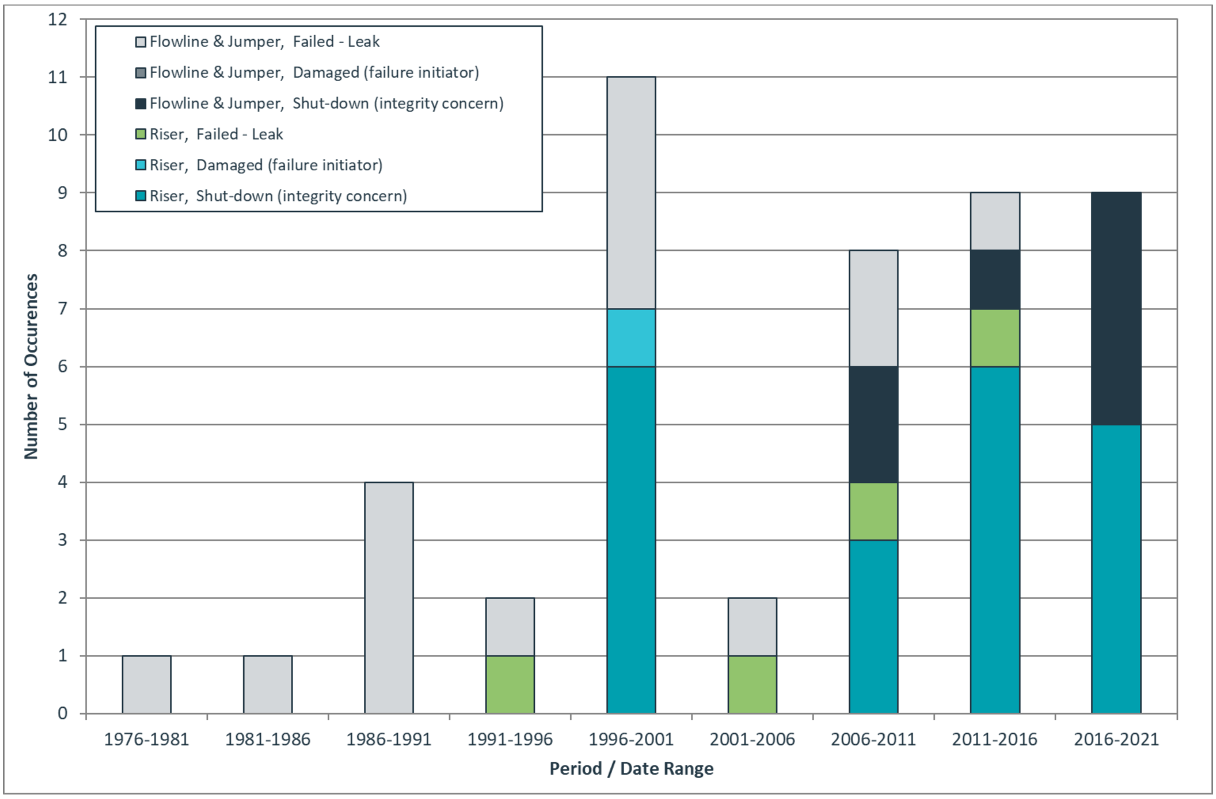


Figure 4.14 Damage & Failure Timeline, Internal Pressure Sheath Ageing

4.4.4.1 Other Integrity Concerns Relating to Polymer Sheath Degradation / Limits

In addition to the degradation experience relating to PA internal pressure sheaths (which account for 54% of manufactured pipes to date), there are a number of additional threats which should be addressed through design and operations of flexible pipes. Whilst these threats have not necessarily all been evidenced in the field and / or reported to the JIP, they do represent credible hazards to flexible pipe. These are summarised below, and further information relating to the other polymer pressure sheaths are summarised in Sections 4.4.4.2 and 4.4.4.3.

<u>*Guidance Note*</u>

Whilst thermal degradation is normally only a concern due to bore fluid temperature on the pipe cross section, it is important to consider the effects of ancillary equipment (e.g. within I-tubes / J-tubes / caissons, beneath bend stiffeners or clamps) and / or seabed burial which may locally insulate the external surface of the pipe from the external environment. There have been several incidents where locally insulated sections of polymers (internal and external sheaths) have experienced significantly accelerated degradation and breakage.

Another potential threat to the outer sheath of flexible pipes occurs above the splash zone and possibly in storage, where the pipe may be exposed to strong sunlight / UV radiation. If the polymer has not been specified for service under UV exposure, the mechanical properties may be compromised with cracking of the outer sheath either in-service, or during installation.

Several operators have previously raised concerns over the effects of transient low temperatures on the internal pressure sheath caused by the Joule-Thomson effect on start-up. Extreme low temperatures, below manufacturer qualification limits, have been experienced for short durations. However, no in-service failures are known to have been attributed to this, although the JIP is aware of two operators that have recovered pipes due to integrity concerns *relating to this mechanism. In those cases, detailed dissection did not identify any notable degradation / defects. It is anticipated that embrittlement risks may have been mitigated to date by the fact that it is typically static jumpers / flowlines which are locally exposed over short periods of time due to their close proximity to choke valves. Local cross section analysis has also been employed to validate the through-thickness temperature profile, and corresponding threats, across the pressure sheath.*

4.4.4.2 Polyvinylidene Difluoride (PVDF)

The group of Polyvinylidene Fluoropolymers (PVDFs) are commonly used in high temperature applications for the inner sheath material of flexible pipes, and account for 24% of manufactured pipes to date. These polymers have a relatively wide range of mechanical and chemical properties, which are modified by the compounding of the original material, its processing treatment and any additives that may be included to modify processing and properties further. New PVDF grades continue to be developed and qualified by the manufacturers and sub-suppliers.

<u>Guidance Note</u>

PVDF was developed by the manufacturers to meet the industry needs in terms of increased reservoir temperatures, with a nominal maximum design temperature of ~130°C. Unlike Polyamide (PA) grades, experience has shown that PVDF is largely resistant to ageing mechanisms. The notch sensitive nature of early PVDF grades led some manufacturers to develop multi-layer sheath designs which became a key factor in a number of other Damage / Failure mechanisms, as described in the following sections:

- Section 4.4.5, Internal Pressure Sheath, End Fitting Pull-out
- Section 4.4.7, Carcass Failure, Multilayer PVDF Collapse
- Section 4.4.12, Carcass Failure, Tearing / Pullout
- Section 4.4.13, Internal Pressure Sheath, Fatigue / Fracture / Microleaks

However, all manufacturers now offer fully qualified, single layer PVDF solutions to mitigate these risks.

4.4.4.3 Polyethylene (PE)

PE has good resistance to acids (depending on concentration) and water. Several PE grades are available for internal pressure sheath application, as summarised in the API 17B ongoing updates:

- High density polyethylene (HDPE) or medium density polyethylene (MDPE) is not widely used in hydrocarbon service. Its use is normally in water injection applications and low pressure / temperature production fluid. HDPE / MDPE is typically used in the temperature range of -50°C to +65°C. When exposed to hydrocarbon gases, HDPE and MDPE are susceptible to blistering if rapidly depressurised from high temperature and pressure operating conditions. Pipes with HDPE / MDPE internal pressure sheathes, defined as Polyethylene (PE) account for ~13% of all manufactured pipes to date.
- Cross-linked polyethylene (XLPE) is a form of PE manufactured using one of several proprietary cross-linking methods to produce polymers suitable for higher temperatures than HDPE / MDPE (typically 90°C / 1500psi and 70°C / 3000psi but in some cases increased to 95°C / 10,000psi). XLPE is suitable for gas, oil and water applications and exhibits improved blistering resistance (when compared with HDPE / MDPE). XLPE is used as an alternative to polyamide in high water cut / high temperature service. There is limited industry experience where XLPE has exhibited an increased permeability to liquid hydrocarbons that has resulted in produced fluids either being identified at the topsides vents, or filling the annulus at a rate higher than anticipated in design. No failures have been identified, and ongoing research / testing is being performed to quantify permeability to longer-chain hydrocarbons.

- All flexible pipe manufacturers now offer PE grades with improved temperature capability, typically in the range of -50°C to +90°C / 10,000psi. These grades are suitable for gas, oil and water applications.
- For the purposes of reporting, the JIP combines XLPE and Improved Temperature PE (ITPE) pipe population statistics given their similar applications and temperature limits. These internal pressure sheath materials account for ~9% of all manufactured pipes up to 2021.

Similar to the PVDF material detailed above, research, development and qualification of alternative PE grades is an ongoing process with manufacturers and sub-suppliers to optimise pipe design / performance.

4.4.5 Internal Pressure Sheath, End Fitting Pull-out

Pull-out of PVDF internal pressure sheaths account for 43 cases in the database, including 19 *Leak* incidents. However, all but one of the reported *Leak* incidents occurred before 2000. The latest database entry relating to this failure mechanism is from 2012 where a pipe leak was attributed to progressive displacement of the sealing arrangement. Information relating to corresponding testing and qualification is given in Annex A of Ref. [1].

Two flowlines are listed in the database as *Minor defect / damage*. These lines have been identified by the operator as at risk of PVDF end fitting pull-out but continue to operate with maximum temperature / minimum pressure restrictions to mitigate the potential threat.

Guidance Note

All pre-2000 failures were caused by inadequate crimping of the internal pressure sheath in the end fitting in combination with high plasticiser content and a relatively high coefficient of thermal expansion of affected PVDF pressure sheath material grades. Over time, thermal cycling on restart / shutdown allowed the sheath to contract and expand, gradually pulling out from the crimp / seal. As noted, most failures occurred in the mid 1990s and the updated design and manufacturing methods utilised are widely considered to mitigate the risk.

However, in response to the 2012 leak event, one operator re-terminated spare pipes and continues to perform periodic x-ray inspection of the end fitting sealing arrangement on a limited number of pipes to monitor for progressive displacement.

4.4.6 Vent System Anomalies / Blockage

Annulus vent systems are required to relieve the pressure from gases that permeate through the internal pressure sheath and enter the pipe annulus. In cases where annulus pressure is not relieved through a vent system, the excess pressure can lead to bursting / rupture of the outer sheath. In a riser application, the location of any burst is likely to be close to the waterline due to the minimal pressure differential from the external hydrostatic head. This can, and has in the past, led to severe corrosion and failure of the flexible pipe armours in the highly oxygenated splash zone.

The inability to vent an annulus can be caused by a number of reasons, as follows:

- Vent plugs used for installation phase were not removed prior to operation,
- Annulus vent system was not tied-in to vent ports (there is also some industry experience where attempts were mistakenly made to tie-in vent systems to epoxy fill ports on the end fitting, leading to outer sheath rupture due to over-pressurisation),
- Inadvertent closure of isolations, or failure of flow control valves, leading to isolation of the vent system,
- Inadvertent filling of vent system with chemicals / productions and / or blockage from 3rd party drains or common manifolding of multiple risers,
- Blockage of 1 or more (of typically 3) annulus vent tubes within the annulus. In subsea applications, there

is experience that marine growth / seabed debris has contributed to blockage of vent ports in jumper / flowline end fittings. Other malfunctions / ageing of subsea vent systems may result in similar blockages.

In addition, a number of corrosion related *Ruptures* have occurred in recent years with the root cause attributed to having open / air breathing venting arrangement (see Table 4.18 for details).

Vent system anomalies / blockage account for 42 cases in the database, with the vast majority being classified as *Damage* or *Minor defect / damage*.

Guidance Note

In the case of a blockage of vent ports, there are a number of ways to relieve the annulus pressure to minimise risk. One approach which has been employed by some operators is to install a bespoke clamp around the outer sheath at a position below the end fitting and to create a controlled vent path through the clamp and outer sheath.

There is speculative industry feedback that annulus blockages relate to "older design" pipes where the finishing of fabric tapes near the end fitting and excessive use of manufacturing lubricants, both of which are potential causes of blockage, have been improved in recent years through updated manufacturing processes. However, there is not a large enough population base / detail within the damage and failure database to validate this theory.

Free venting of end fittings to atmosphere should be avoided to mitigate corrosion threats from atmospheric ingress, particularly for risers in intermittent operation. In addition, annulus vent systems should include a means of preventing backflow (e.g. NRV) for each individual riser. Refer to Figure 6.2 and Table B.20 for further detail.

4.4.7 Carcass Failure, Multilayer PVDF Collapse

Rapid depressurisation in a flexible pipeline featuring multi-layer pressure sheaths can create a temporary pressure differential between internal sheath layers and the pipe bore. Permeated gases build up in the interstitial boundaries between the layers and expand when the bore pressure drops. As the outer layers are constrained by the pressure armour layer, the expanding gas can create sufficient force against the inner pressure sheath layers to collapse the carcass. To date, this mechanism has only been experienced on 3-layer PVDF products, however 2-layer designs could also be susceptible. It is important that manufacturer specified decompression rate limits are adhered to.

There are 39 reported incidents within the database relating to this degradation mechanism, 37 of which are related to Risers and have dates associated with them. Figure 4.15 shows the timeline of this failure mechanism, showing the first incidents being reported after 2001. As shown in the database, the initial carcass collapse does not always result in *Failure* of the riser (6 *Leak* incidents are identified, compared to a corresponding 23 confirmed *Damage* incidents on the timeline). In the last 5-year block, there has only been 1 reported incident (a *Leak* in a 24-year old pipe). This demonstrates how the industry has adapted to this failure mechanism with evolution in PVDF material composition / pipe design meaning that fewer multilayer PVDF pipes are entering service. Similarly, existing multilayer PVDF pipes have either been decommissioned, replaced or continue to operate but with tighter operational guidelines (particularly with respect to allowable depressurisation rates).

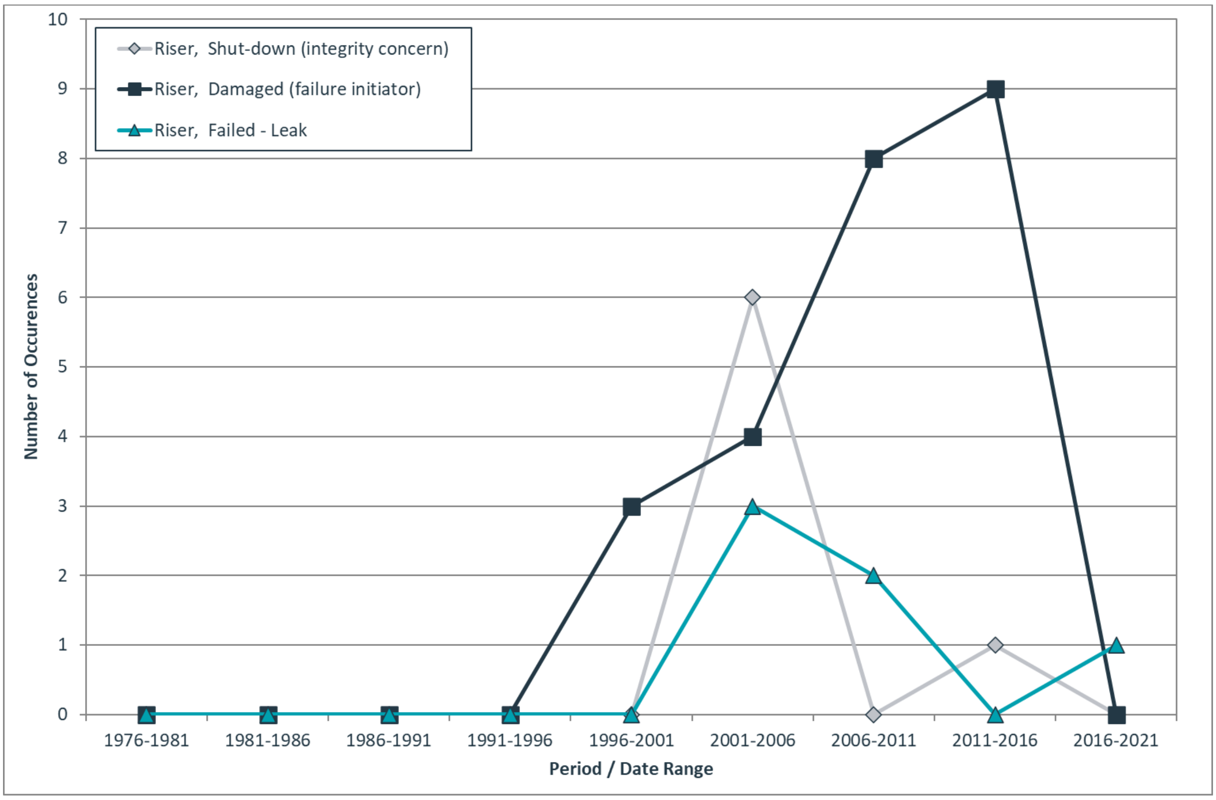


Figure 4.15 Damage & Failure Timeline, Carcass Failure, Multilayer PVDF Collapse

<u>*Guidance Note*</u>

Previous damage experience has either been identified by pieces of carcass being discovered in topside chokes / valves / process vessels, or alternatively by internal inspection of the top riser section. It is possible that there may be lines in operation which have suffered damage to some extent but not yet failed.

A further factor in some of the damage experience is the reduced carcass collapse resistance as a result of the high contact pressure between a riser and mid water arch, coupled with the potential for trapped gas to naturally migrate upwards to a high point.

Carcass failure in multilayer PVDF pipes has typically been limited to pressure sheath designs which include sealing of more than one layer within the end fitting. Later pipe designs by those manufacturers affected by the failures (post-2002) were modified such that only the pressure sheath layer is sealed at the end-fitting. In this case, although the failure mechanism may still occur if depressurisation rates are sufficiently high, the collapse risk is reduced as the interstitial gas can vent into the bore at the end fittings.

Typical linear maximum depressurisation rates for flexible pipe to mitigate this collapse threat is ~100barg/hr, and in some cases "hold periods" are required for a number of hours at specific pressures when depressurising from higher operating pressures. Acceptable depressurisation rates to mitigate collapse should be agreed with the manufacturer. It is important to ensure that process monitoring is sufficient to control and record operating pressure at a suitable interval to ensure these depressurisation rates can be verified.

Given the advancements in qualifying single layer PVDF designs there has been a trend within industry to move away from multilayer designs thus mitigating this failure mode threat.

4.4.8 End Fitting Leak / Failure

There are 29 reported incidents of *End Fitting Leak / Failure*. Seven of these incidents have occurred since the previous iteration of the JIP. The details surrounding the most recent *Failure – Leak* events are summarised as follows:

- 3 cases of water injection jumper *Failures* (on a single asset) where the root cause is reported to be rapid pressurisation / depressurisation (and resulting "water hammer" effect) causing a degradation of the internal pressure sheath crimping within the end fitting. Dissection findings led to end fitting design / manufacturing improvements.
- 3 cases of end fitting *Failures* on water injection pipes where the root cause was reported to have been a failure of the front sealing ring due to contact with the injection water, most likely due to inadequate design and / or assembly error.
- 1 case of a water injection flowline where corrosion of the internal pressure sheath crimping ring allowed bypass of fluid into the annulus and leakage after approximately 30 years in service.

4.4.9 Tensile Armour Wire Breakage (including fatigue & corrosion-fatigue)

There are 26 reported incidents of *Armour Wire Breakage*. This is a significant increase compared to the previous iteration of the JIP (6 cases). These cases are summarised as follows:

- 5 cases relating to accelerated fatigue or corrosion-fatigue damage due a combination of actual Metocean data being more severe than design, and a FPSO turret seizure that led to the FPSO being exposed to a beam sea environment for an extended period of time. In addition, one of the risers had previously had a flooded annulus to the top, which was partially drained but left the tapes wet in the bend stiffener high fatigue area. As the annulus vent system was open, breathing resulted in moist atmospheric air being drawn into the riser annulus. These factors combined resulted in *Failure* by *Rupture* of 1 riser and *Damage* to 4 others (3 of which were re-terminated and 1 of which was shut-down due to integrity concerns).
- 4 cases relating to wire fatigue failure in the region of the bend stiffener, where local contact loading (driven by high tension and interface loading) was not adequately assessed in design (Section 4.4.2.1). The locations of fatigue damage relate to an above water bend stiffener i.e. a dry annulus:
    - 1 case resulting in *Rupture* of the riser. Subsequent dissection confirmed a large number of fatigue failures prior to plastic failure of the remaining tensile wires. Further information relating to this, and other, *Rupture* failures is presented in Table 4.18 within Section 4.5 of this report.
    - 3 cases of *Damage* where a number of fatigue breaks have been identified within the bend stiffener region using accelerometer-based and acoustic emission monitoring. Due to the large number of armour wire breaks recorded, 1 of these lines was shut-down and the subsequent dissection confirmed 19 broken armour wires.
- 8 cases where wear / fatigue of the tensile armour wires was caused by contact between the rigid bend stiffener insert and the flexible pipe (similar to the incidents reported in bullet point 2 above). This design flaw impacted a large number of risers. Changes to the interface design were implemented ~2006 to mitigate the issue for future risers. However, a number of original risers were retained in operation and subsequently failed. The time to failure was between 10 and 20 years. Of the 8 incidents, 5 resulted in *Rupture*, 1 resulted in a *Leak* and the two remaining cases reported as *Damage*. For some pipes, distortion of the outer sheath, indicating excess torsion in the pipe as a result of a large number of tensile armour wire breaks, was evident from ROV inspection footage.

- 3 historic cases relating to wire fatigue failure within the end fitting resulting in *Leak*. The root cause was attributed to local bending and heating of wires during end fitting mounting, leading to higher stresses than expected. The incidents relate to cases where there are combined high bending loads in operation due to the bend stiffener being in close proximity to the pipe end fitting. This mechanism has subsequently been mitigated by design iteration with no further events reported.
- 1 case of a water injection riser *Failure* by *Rupture* caused by a flawed bend stiffener connector interface design. Rattle fit design of the bend stiffener interface locking pins effectively made the riser bend stiffener redundant with all fatigue bending focussed at a single point within the riser J-tube. Resulting corrosion-fatigue failure occurred after 19 years in operation.
- 1 case of a *Failure* by *Rupture* caused by tensile armour wire breakage in / close to the end fitting. Failure occurred in 2017 after approximately 6.5 years in operation. It is reported that the failure was most likely caused by anchoring system / end fitting mounting deficiencies. The failure prompted changes to the end fitting mounting technique to mitigate the issue.
- 1 case of a *Damaged* static water injection riser where multiple wire breaks have been identified using magnetic stress measurement.
- 1 case of a *Damaged* riser where tensile armour wire fractures were identified, most likely as a result of fatigue / corrosion-fatigue.
- 1 case of a *Damaged* riser where dissection upon recovery identified 1 broken tensile armour wire and cracks were evident in 3 adjacent wires. The riser had previously been identified as having a flooded annulus, most likely caused by damage during installation. Damage was identified approx. 9 years after installation.
- 1 case from 1999 where a direct hit from a Category 5 cyclone caused *Damage* to several risers, one of which was reported to have broken tensile armour wires.

<u>Guidance Note</u>

Industry experience to date indicates that, in most cases, fatigue methodologies are demonstrably conservative. The Failure *experience reported to date suggests that specific design oversights or related system failures were important contributory factors in significantly accelerating the observed fatigue damage.*

In cases where the tensile armour fatigue is governing (as opposed to pressure armour) the presence of multiple armours does provide a degree of redundancy. However, fatigue models are based on assessment of fatigue performance up to crack initiation in a single wire. Given that the load increase from an individual wire failure is likely to be locally redistributed, there is growing industry interest in modelling the cross section of flexible pipes after initial armour wire failure. In recent years, further work by specialist contractors considers these effects and the associated acceptance criterion e.g. Ref. [27]. However, at present no industry verified model is believed to exist, and generally the effects are assessed in local FE models on a case-specific basis.

The three principal factors affecting the results of a fatigue assessment are the:

- *Riser structural response*
- *Annulus environment*
- *Material performance and characteristics*

The following sub-sections provide guidance on how the industry is tackling each of these challenges, and in addition the topic of reliability based assessments are reviewed in Section 4.4.9.4..

4.4.9.1 Guidance Note, Riser Structural Response

The riser structural response includes all of the parameters that govern the global and local analysis models to define riser armour curvatures, tensions, and stresses. The global and local models are normally distinct tools with their own established and settled methodologies as incorporated in Annex G of the Recommended Practice for Flexible Pipe (API RP 17B), Ref. [1].

4.4.9.2 Guidance Note, Annulus Environment

There are a number of parameters which affect the annulus environment, principally:

1. *Is the annulus "as-manufactured", or flooded?*
    - *Annulus vacuum testing / pressure testing are regularly utilised to verify the annulus condition. In cases where annulus access is not possible, UT scanning of the flexible can be utilised to confirm if the annulus is liquid filled.*
    - *As noted in the guidance section of Table B.21, the risk of over-pressurising a riser annulus during testing must be carefully managed to avoid causing additional damage to a potentially weakened outer sheath within the air/splash zone.*
2. *If the annulus is flooded, is the cause of flooding known? Critically, is there replenishment of oxygenated seawater close to the splashzone?*
    - *Positive pressure testing following confirmation of a flooded annulus can normally confirm if an outer sheath breach is within the top ~30m (3 barg) of the water column.*
3. *Are there gases in the conveyed fluid which may affect the steel armours (principally CO_2 and H_2S, and water vapour) when they permeate through the internal pressure sheath?*
    - *It is good practice to regularly monitor and record these parameters through the life cycle of the flexible riser, although this is not always possible. Access to this type of data has, in the past, been critical in the life extension and fitness for service assessments for a number of riser systems.*
4. *Are the permeation rates of those gases into the annulus known and / or can they be measured?*
    - *In-situ monitoring of permeated annulus gas has been performed by a number of pipe users in the past which has given some confidence in certain parameters. However, for other constituents, e.g. H_2S, permeated gas may be quickly absorbed / consumed by the steel due to the high surface to free volume ratio in the annulus, giving the potential for "false positives" when interpreting results.*
    - *All of the manufacturers have up to date permeation models, including consumption-based models accounting for the low H_2S flowrates and annulus confinement, e.g. Ref. [72]. In other instances, full scale testing has been performed to validate the updated models. A recent JIP developed an independent permeation model, refer to Section 8.6 for further information , and further research is available in Ref. [45].*

4.4.9.3 Guidance Note, Material Performance & Characteristics - Fatigue

Verification of armour material performance is defined through testing and validation programs. In the case of dynamic service applications, the fatigue performance of the armour material must also be verified. For sour service applications, testing is included to validate and verify HIC / SSC limits.

Historical fatigue approaches have consistently focussed on developing proprietary SN curves, utilising predicted fluid and gas combinations, in a de-oxygenated environment. This testing typically takes several months to complete and is normally performed on "new" material. As such, longer-term corrosion defects are not necessarily captured in this type of testing.

There is growing experience of data from fatigue testing of recovered armour wires which have been subjected to in-service corrosion. These have indicated a reduction in fatigue cycles to failure when compared to control samples (either static / uncorroded / unused samples). A summary of industry available results are:

- *Ref. [24], two cases assessed with reduction in fatigue strength of the corroded specimens represented by fatigue notch factors (FNF) of 1.45. Whilst the number of samples was relatively small and the conclusions were noted to be indicative only, there does appear to be a clear difference in the performance of used/corroded and unused material which in these cases represented factors of circa. 10 and 20 reduction in the number of cycles to failure for a given stress range. The corrosion pits identified on the test samples ranged from a depth of 40µm to 250µm.*
- *Ref. [70], armour samples were tested from recovered (flooded) risers after 23 years service. Again, the sample size was relatively low, but it was concluded that the fatigue strength had reduced to ~50% when compared against parallel testing on unused / stored risers manufactured in the same era.*
- *Independent experience indicating the number of cycles to failure reducing to ~67% when compared against parallel testing on unused virgin material.*

Although the number of riser samples that have been assessed using this approach is limited, it appears that the initial defect condition and the subsequent crack initiation / growth of that defect is the most significant factor, and that traditional corrosion-fatigue testing in accelerated conditions may not fully account for environmental effects on the samples (also Ref. [28]). Previous industry experience also indicates that once pitting corrosion has occurred the mechanism of corrosion-fatigue remains largely unknown. In cases where an oxygenated environment exists, the critical defect depths may be reached relatively quickly.

There is growing industry acceptance that if a riser has been designed with suitable factors of safety, then the in-service fatigue damage that would be expected would be very limited (~<5%), assuming there are no major load variations unaccounted for in the fatigue analysis. As such, fatigue testing on recovered wires is unlikely to be able to validate this level of fatigue damage, given the scatter that is expected in fatigue testing. There is growing industry experience that the "life reduction" being experienced from testing of recovered wire is the result of armour wire defects that are larger than those resulting from the de-oxygenated design SN curves. It is believed these are the result of either moderately oxygenated conditions in service, or post-recovery, at the wire sampling locations, as opposed to significantly more aggressive in-service riser loading regimes.

The JIP are aware of individual operators that investigated the feasibility of applying fracture mechanics / crack growth measurement techniques through external testing dating back to the early 2000s. However, at present there is not believed to be an industry validated model, though there have been industry efforts to develop these approaches with some focus on accounting for frequency affects (reduced frequency increasing the crack growth rate) and developing methods for inducing representative accelerated pitting.

4.4.9.4 Guidance Note, Reliability Assessments

Reliability based design can be applied as an alternative design method (Ref. [4]). However, the JIP is only aware of limited industry experience in this approach, Ref. [26].

Instances where this method has been used include the re-assessment of corrosion-fatigue service lives. In one example, a conventional fatigue assessment confirmed that the effective factor of safety was below that required by the design code. The reliability based assessment considered and utilised all data relating to vessel motions and riser operating history, which when combined with probabilistic distributions of the key parameters allowed a failure probability to be defined. This annual failure probability was then compared against the relevant acceptance criteria defined by the regulatory regime, allowing continued operation for a limited period of time.

4.4.10 Tensile Armours - Birdcaging

The JIP birdcaging statistics are dominated by deepwater applications in which high compression and / or bending occurs at the seabed touchdown point. In these cases, degradation of the high strength tape layers was a causal factor (either through abrasion, or thermal degradation). Of the 20 incidents reported, 1 has been reported as a *Rupture* event, 13 *Leaks* and 6 *Damages*.

<u>*Guidance Note*</u>

The reported statistics relate to radial buckling of tensile armour wires i.e. birdcaging. In the reported Rupture case, thermal degradation of the high strength tapes in combination with self-burial of the pipe were identified as causal factors, the bore operating temperature was in the region of 100 – 110°C (see Table 4.18 for further details).

The absence of reported experience of lateral buckling of armour wires was investigated during the previous iteration of the JIP. There remains no direct experience of in-service failure that the JIP is aware of. However, one member previously noted that the mechanism would tend to initiate on the inner armour wires, and that it was feasible that there may be cases where the mechanism has initiated and the pipe is effectively damaged (but not failed). In such a scenario, it would be almost impossible to identify the damage until it has progressed to failure.

4.4.11 Overbend / Pressure Armour Unlock

There are 18 reported incidents of *Overbending / Pressure Armour Unlock*. Of those incidents, 1 is reported as *Failure* by *Rupture*, 12 as *Failure* by *Leak* and 5 as *Damage*.

15 of the 18 incidents reported have associated *Failure* dates (1 *Rupture*, 9 *Leak* and 5 *Damage*). The timeline of these incidents is shown in Figure 4.16 below, confirming that the vast majority of incidents occurred between the early 1990s and the mid 2000s. However, the latest 5-year block does show an increase in reported overbending incidents:

- 1 case of *Failure* by *Rupture* of a flowline during operation where the underlying cause was identified to be overbending / pressure armour unlock that likely occurred during installation.
- 1 case of *Failure* by *Leak* of a static riser that occurred approximately 25m from the subsea riser end fitting after 23 years in operation (i.e. beyond the original design life of 20 years). After dissection, the root cause was attributed to overbending before or during installation resulting in unlocking of the pressure armour and a weakness in the pressure liner (which ultimately led to a leak over time).
- 2 cases of *Damage* caused by overbending close to a pipe end fitting during onshore handling. Both were repaired prior to entering service.

From the 18 reported incidents, 4 were identified to have resulted in *Failure* by *Leak* and occurred during operations, as follows;

- 2005, flowline, believed to have been caused by unlock in manufacture / installation,
- 1999, flowline,
- Un-dated failure, subsea jumper,
- Un-dated failure (but pre-2010), dynamic WI riser.

This data indicates that, to date, the in-service threat of overbending / unlock in dynamic risers during storm events is low, or that if they have occurred in service in low pressure applications they have not progressed to pipe failures. It should be noted that a safety factor of 1.1 is adopted between the pressure armour locking radius and the storage MBR, in accordance with API 17J. Furthermore, all of the events reported in recent years have been attributed to handling / installation related damage.

<u>*Guidance Note*</u>

The database shows that 67% of the incidents (i.e. 12 of 18) occurred during or prior to the installation phase of the pipe, explaining why not all events resulted in leaks. The incident data highlights the importance of careful handling and management of installation activities to mitigate life cycle threats.

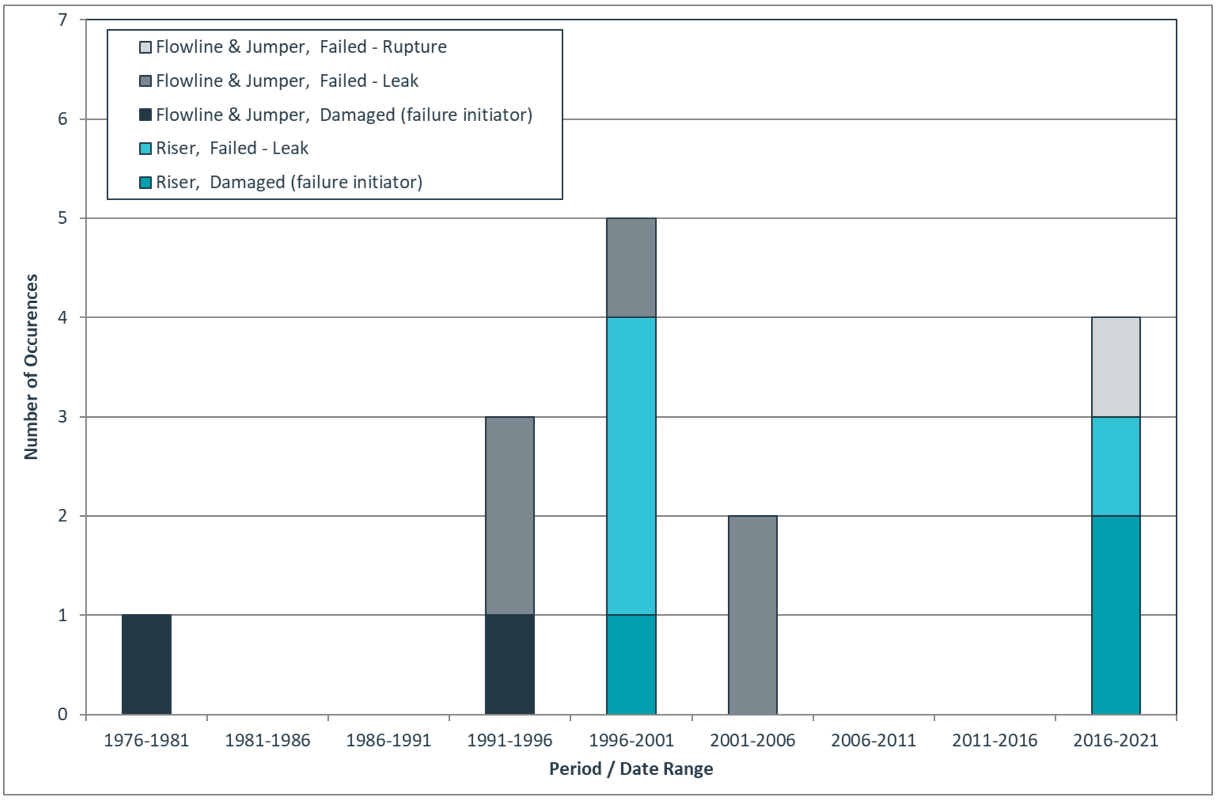


Figure 4.16 Damage & Failure Timeline, Overbend / Pressure Armour Unlock

4.4.12 Carcass Failure, Tearing / Pullout

There are 17 reported incidents in the database relating to *Carcass Tearing / Pullout*, with 5 resulting in *Failure (Leak)*, 7 cases identified as *Damage / Minor Defect* and a further 5 being shut-down due to integrity concerns.

Two of the *Leak* incidents in Flowlines have been attributed to hydrate plugs and / or their remediation. In addition, a *Damage* incident has been reported that attributes observed carcass collapse / tearing to differential pressure across a hydrate plug (with the damage reported to have occurred on the low pressure side of the plug).

A *Leak* identified on a topside jumper was attributed to excess loads induced by the configuration leading to abnormal stresses in the carcass strip. This led to a further 5 topside jumpers of the same design being shut-down as a precaution.

The first incidents occurred in the early 2000s, with the most recent damage incident occurring in 2018 (hydrate plug event detailed above).

Guidance Note

Multi-layer PVDF pipes are more susceptible to carcass pull out or carcass tearing than single layer designs. Excessive axial load in the carcass can cause tear out at the end fitting. Industry experience of the mechanism is presented in Ref. [31] & Ref. [32]. Carcass tear out is caused by relative motion between the core (i.e. the carcass and innermost sheath layer) and the outer pipe layers over a certain length of the riser. Volume loss of the PVDF layer (due to loss of plasticiser over time) is a contributory factor. Tear out occurs when the carcass is fully extended and the applied internal loading, caused by the relative motion within the structure, exceeds the axial capacity / fixation capacity of the carcass. In addition, the carcass may alternatively be overloaded by the application of excess pressure to a blockage within the pipe bore or other abnormal loading.

Manufacturers and other consultants have developed independent tools / models to quantify the risk of carcass damage during hydrate and / or stuck pig remediation activities.

Carcass damage can be investigated from the pitch or ovality of the internal diameter of the pipe. Loss of containment from the carcass collapse and tearing may be mitigated through inspection and monitoring, refer to Section 5.0, which may allow early identification of carcass extension prior to failure (further guidance on differential pressure monitoring is also given in Appendix B, Table B.18). However, the major limitation of such physical inspection is the pre-requisite to perform bore flushing, isolation, and breaking of containment prior to deploying the internal inspection equipment.

4.4.13 Internal Pressure Sheath, Fatigue / Fracture / Microleaks

There are 15 reported incidents of *Fatigue / Fracture / Microleaks* relating to the internal pressure sheath. Almost all of these incidents relate to PVDF materials and can be summarised as follows:

- Incidents initiated at ridges on internal sheath associated with manufacturing extrusion / creep into carcass and / or pressure armour layer gaps. This experience largely relates to static jumpers where cracks initiated on the inner surface at ridges at the carcass / sheath extrusion interface.
- Suspected cracking of internal (and / or sacrificial) sheath in dynamic riser service.
- Incidents relating to excess installation loads or overstrain in-service e.g. around MWAs or in topsides dragchain applications.
- Crazing / cracking / splitting of sheath in a high pressure application, identified during FAT and separately during offshore leak test.

Dates are available for 13 occurrences. The first incidents reported occurred in the late 1990s. There have been no *Damage* or *Failure* incidents reported in the latest 5-year block, as illustrated in Figure 4.10 and Figure 4.11.

4.4.14 Global Pipe Defect, Pipe Blockage (Wax / Hydrates / Other)

There are 13 reported cases in the database relating to blockages in flexible pipes, two of which occurred since the last iteration of the JIP that were categorised as *Minor Defect / Damage*. While none of the reported blockage incidents have themselves caused a *Failure* it is known that the differential pressure across a hydrate plug has led to carcass tearing resulting in a *Leak* on at least two occasions (see Section 4.4.12).

Guidance Note

There is some experience relating to blockages in flexible pipes. These are reported to have been caused by either hydrates or excess sand production / drop-out in flowline sections. In all cases, it should be noted that the flexible pipe design is not specifically believed to be a factor in the blockage, and that the incidents could equally have occurred on alternative pipe types.

4.4.15 Smooth Bore Liner Collapse

Smooth bore pipes account for ~10% of the total supplied pipe sections and are typically used for water injection applications (~88% of all smooth bore pipes) as there is no concern with gas pressure build up in the annulus, leading to possible collapse of the internal pressure sheath if the bore becomes depressurised. They are also predominantly used as static flowlines / jumpers (~79% of all smooth bore pipes).

There are 12 reported incidents of *Smooth Bore Liner Collapse*. The incidents can be summarised as follows:

- A recent case where a 12km line was installed between two platforms. There was a delay in connecting to platform piping so the pipe was left full of water for ~3 months (with the valve on the pulling head closed). During that time, water shrinkage occurred due to temperature variation, resulting in a suction effect at the topside while retaining a residual pressure in the annulus. Following discovery of the damage, the liner was re-inflated by creating a vacuum in the annulus and applying heat to the area. The pipe then passed a 24-hour integrity test at 1.1 * design pressure.
- 3 historic cases where the riser was subject to 23barg external pressure in a J-tube leading to "reverse permeation" into the annulus. This allowed the internal pressure sheath to collapse and fail during shutdown. On restart the intermediate (anti-collapse) sheath overloaded the tensile armours, as the pressure armour was by-passed, leading to *Failure* by *Rupture*.
- Several cases where a vacuum was created inadvertently in the bore during topsides shutdown (repeatedly in certain cases) prior to failure and / or the annulus was flooded. Two of these cases related to topsides jumper applications and one to a dynamic riser.
- A historic case where a vacuum was inadvertently pulled during installation resulting in collapse of the smooth bore liner.
- Liner collapse was believed to have been caused by vent system blockage and annulus over-pressurisation.
- Water injection riser smooth bore collapse, reported to have been identified through annulus testing which identified a significantly increased annulus free volume. Upon investigation, pipe bore was determined to be at vacuum during the annulus test. Therefore, the annulus test was repeated with the bore pressurised. This confirmed an intact free volume in the annulus and aligned with previous test results. Classed as *Damage*.

<u>*Guidance Note*</u>

For smooth bore pipes in riser applications, operational focus is required to ensure that the riser bore remains filled / pressurised to mitigate collapse caused by hydrostatic pressure from annulus flooding where an anti-collapse layer is not deployed. Some operators have deployed vacuum-breaker technologies to mitigate this threat, which automatically re-pressurise the pipe bore from a topsides nitrogen source when the riser bore approaches vacuum pressures. As per the final bullet above, bore pressure should be maintained and monitored during annulus testing, specifically for smooth bore risers.

There are a limited number of smooth bore risers deployed in gas service to mitigate FLIP threats initiated by the carcass profile, refer to Section 4.1.2.1 and Ref. [23].

4.4.16 Other

The "Other" *Damage / Failure* grouping collectively includes 43 incidents, spread across 11 causes which are bulleted below.

Two incidents have resulted in *Failure* by *Rupture*. One of these was caused by *Excess Tension* (occurred in 1987). The other was caused by Excess Torsion during transpooling of a flowline from a reel into an installation vessel carousel, the pipe subsequently ruptured during the offshore leak test (two other pipes were damaged during the same transpooling operation).

- Dropped Object / 3rd Party Interaction / Dragging — 13 cases (inc. 1 *Leak*, 3 *Damage, 7 Minor Defect / Damage* and 2 *Shut-down integrity concern*)
- Upheaval Buckling — 7 cases (inc. 3 *Leaks*)
- Flow Induced Pulsation — 5 cases (all *Shut-down integrity concern*)
- Excess Torsion — 4 case (1 *Rupture*, 1 *Leak, 2 Damage*)
- Ovalisation — 4 cases (all *Damage*)
- Rough Bore Collapse — 3 cases (1 *Leak*, 2 *Damage*)
- Internal Damage - Pigging — 2 cases (both *Damage*)
- Carcass Fatigue Failure — 1 case (*Leak*)
- Excess Tension — 1 case (*Rupture*)
- Excess Marine Growth — 1 case (*Damage*)
- Mechanism Disputed — 2 cases (inc. 1 *Leak*)

4.5 Desensitised Summary of the Most Critical Incidents, Failures by Rupture

There are 34 incidents (3.9% of all degradation / failure events in the database) which resulted in a *Failure* by *Rupture* of the flexible pipe. The details of these are summarised in Table 4.18 below. Note that unshaded rows indicate new *Rupture* incidents identified during this phase of the JIP (15 of which have occurred since 2016).

In addition, Figure 4.17 presents a histogram showing the time to failure for each rupture (grouped into 5-year blocks). Each bar of the plot is also discretised to show a breakdown of the failure mechanisms attributed to each incident.

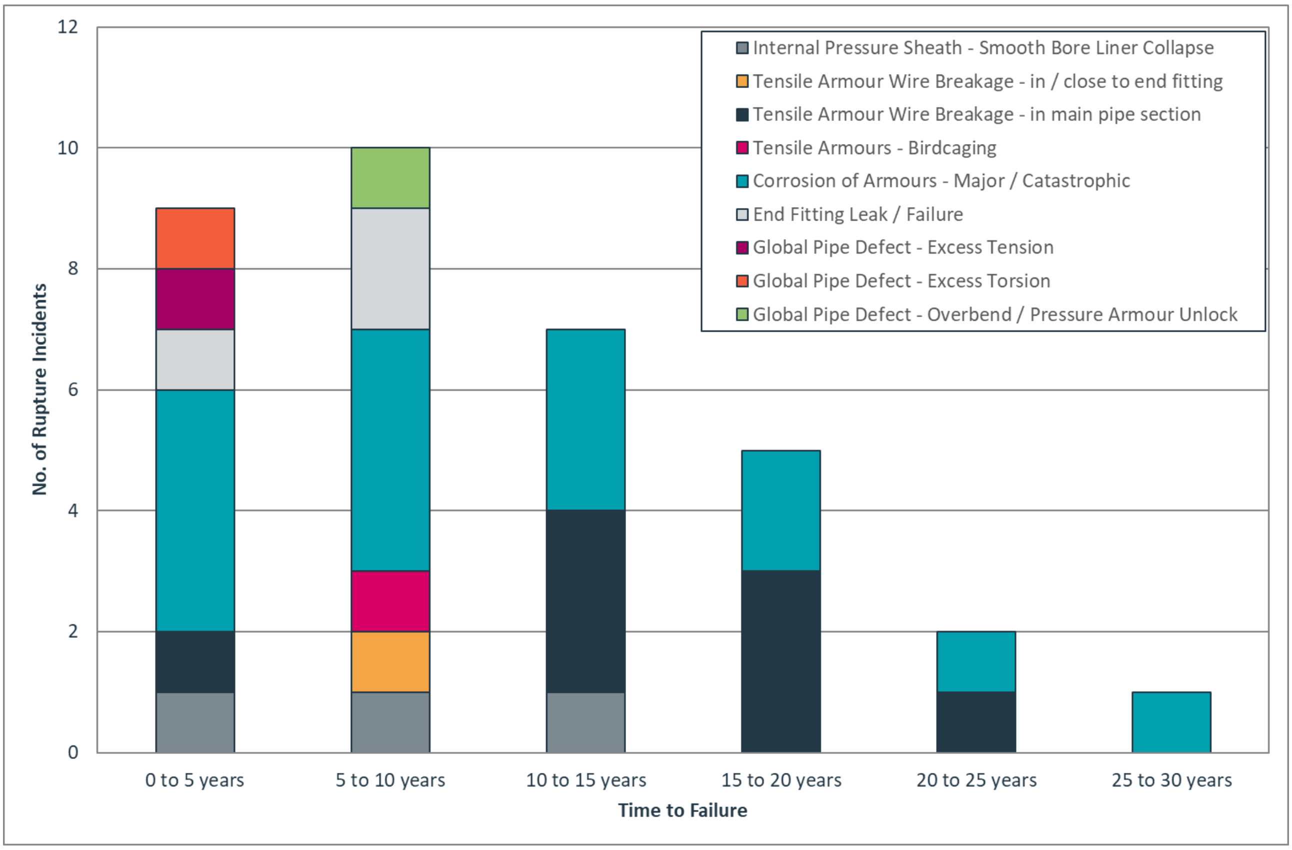


Figure 4.17 Rupture Incidents, Time to Failure

Table 4.18 Reported Incidents resulting in Failure by Rupture

Failure Year(s)	Mechanism	Description	Type of Pipe Affected	Applicability to other Pipes	Mitigations
1987	Excess Tension	There is limited information relating to this failure. The failure occurred within 1 year of installation, with the possibility that it was either the result of an accidental event or related to a design issue.	Dynamic riser	Applicable to any other flexible pipe.	Adequate design, and elimination of threats relating to accidental damage.
1993	End Fitting Leak / Failure	A large void in the epoxy resin within the end fitting, resulting in unsupported areas, caused the internal pressure sheath to thin at points of high shear strain. This led to the polymer fracturing, allowing pressurised fluids to enter the riser annulus. Rupture occurred during field commissioning as a result of reduced pressure retention capacity.	Jumper, water injection	In theory, applicable to any other flexible pipe.	Advances in end fitting design and manufacturing processes mitigate the threat.
1998	End Fitting Leak / Failure	Failure originating from end fitting where the end of the pressure armour layer and the lip of the pressure sheath were in close proximity. Resulting stress concentrations led to cracks / crazing of the pressure sheath at this location. Cracks developed into circumferential cracks over a number of years, eventually resulting in pipe rupture after ~5 years service.	Jumper, water injection	In theory, applicable to any other flexible pipe.	Advances in end fitting design and manufacturing processes mitigate the threat.
1995, 2001, 2005	Smooth Bore Liner Collapse	Riser was subjected to 23barg external pressure in a J-tube leading to "reverse permeation" into the annulus. This allowed the internal pressure sheath to collapse and fail during shutdown. On restart the intermediate (anti-collapse) sheath overloaded the tensile armours, as the pressure armour was by-passed, leading to *Failure* by *Rupture*. See also Section 4.4.15. Time to failure varied between 2 and 10 years.	Smooth bore water injection static riser	Only applicable to smooth bore risers (with an intermediate sheath) with potential for annulus over-pressurisation.	Bore pressure monitoring system to maintain pressure above collapse pressure based on maximum expected annulus pressure.
2004	Tensile Armours - Birdcaging	Flowline annulus became flooded (likely due to outer sheath damage that was repaired with a plastic weld during installation). The flooded annulus, combined with self-burial of the line and high operating temperatures, caused substantial ageing of the high strength tapes. This led to the birdcaging failure upon depressurisation of the line (after ~5 years service). The birdcaging occured at the location of the sheath repair due to external sheath weakness at this location.	Flowline, production	Applicable to other flexible pipes exposed to the same installation damage and specific operating conditions.	Adequate design, and elimination of threats relating to accidental damage.
2004	Corrosion of Armours - Major / Catastrophic	Static riser ruptured in J-tube as a result of free (oxygenated) corrosion of the tensile armour wires. Corrosion occurred because of the external sheath burst near the waterline, due to blocked annulus vent tubes / system. The gas release was fully downward, by the subsea opening of the J-tube. Failure occurred after ~13 years operation.	Static riser	Applicable to any other flexible pipe subject to permeation of gas into the annulus and / or with the potential for mechanical damage close to the oxygenated splashzone	Annulus monitoring and / or vent port communication testing, with implementation of remedial actions if required e.g. installation of vent collar, J-tube inhibition etc.
2007	Corrosion of Armours - Major / Catastrophic	Global corrosion near waterline, likely the result of oxygenated seawater corrosion. Vent plug was not removed from riser end which failed and likely led to a sheath burst close to the water line. Sheath damage was identified ~2 years prior to failure, but there was doubt over the effectiveness of the repair. Failure occurred after ~10 years operation. The resulting fire/explosion led to multiple fatalities.	Dynamic transfer line, production		Remove vent plugs following installation and install vent system. Perform annulus monitoring program and remediate any defects. Ensure the integrity of any repair clamps is verified.
2007	Corrosion of Armours - Major / Catastrophic	Riser vent plugs were not removed following riser installation. No annulus vent system or monitoring program in place. No I-tube inspection. Annulus over-pressurised due to permeated gas causing breach close to the splash-zone. Over time, armour wires corroded in an oxygenated environment until the riser catastrophically failed. Failure occurred after ~12 years operation. Failure was identified by a sudden pressure drop in the line and gas alarms in the turret area of the FPSO. See also Ref [73].	Dynamic riser, production		Remove vent plugs following installation and install vent system. Perform annulus monitoring program and remediate any defects.

Failure Year(s)	Mechanism	Description	Type of Pipe Affected	Applicability to other Pipes	Mitigations
2008	Corrosion of Armours - Major / Catastrophic	HP 3-inch ID test jumper subsequently used in multiple choke and kill applications 12 years after manufacture. External carcass and sheath intentionally drilled through as the jumper was not supplied with a venting system. After a further 7 years (i.e. 19 years total service), the jumper ruptured during HP testing near the end fitting due to local severe atmospheric corrosion.	Topsides / test jumper	N/A to facility pipe; very specific operational history.	Adhere to operation and maintenance manual.
2010	End Fitting Leak / Failure	End fitting parted during pressure test at 360bar (leak test pressure). Failure occurred after ~6 years operation. Failure investigation concluded ductile failure due to overloading of armours. The root cause was unclear as material testing returned results within specification. A potential cause was deemed to be installation overload / damage.	Flowline, production	Potentially applicable to any other flexible pipe	Adequate design, and elimination of threats relating to accidental damage
2013, 2018, 2019	Corrosion of Armours - Major / Catastrophic	Failure of three pipes attributed to hydrogen induced cracking / stress sulphide cracking of high strength, sweet service armour wires. All pipes were 55° tensile armour wire lay angle pipe designs (i.e. no dedicated, interlocked pressure armour layer). In addition to these *Rupture* incidents, a number of *Leak* incidents have been attributed to the same failure mechanism, see Section 4.4.3 for further information. Failures occurred between 14 and 29 years operation.	Dynamic riser, gas import / export (2013) Flowline, production (2018, 2019)	Potentially applicable to any flexible pipe with high strength steel armour wires in the presence of H_2S, particularly in 55° tensile armour wire pipes in which armour utilisations tend to be higher.	Suitable armour wire material selection.
2014, 2015 (x2), 2017, 2019	Tensile Armour Wire Breakage - in main pipe section	Failure of five dynamic risers attributed to a systemic flaw in the bend stiffener interface design. Contact between the rigid bend stiffener insert and pipe in a high tension application resulted in fatigue of the tensile armour wires. ROV inspections identified observable pipe twist caused by a torsional imbalance as a result of multiple tensile armour wire breakages. Design of bend stiffener interface adapted in ~2006 to mitigate contact issue. Failures occurred in range of 11 to 20 years after startup.	Dynamic risers, various	Applicable to any other flexible riser subject to high fatigue loads in operation.	Detail assessment of local interface loading. Consider implementation of armour inspection systems in high-risk systems to verify initial breaks prior to failure.
2015	Corrosion of Armours - Major / Catastrophic	Catastrophic failure of water injection riser just above waterline, ~5 years after startup. Evidence suggests that the outer armours corroded due to an external sheath breach close to the waterline, allowing the inner armours to unwrap, leading to internal pressure sheath failure / rupture.	Dynamic riser, water injection	Applicable to any other flexible pipe subject to permeation of gas into the annulus and / or with the potential for mechanical damage close to the oxygenated splashzone.	Perform annulus monitoring program and remediate any defects. Ensure the integrity of any repair clamps is verified.
2015	Tensile Armour Wire Breakage (Fatigue)	Production riser fatigue failure at bend stiffener (above waterline). High tension application and concentrated fatigue load in interface section just above root of bend stiffener leading to fatigue failure of a large number of tensile wires. Once sufficient armours had failed through fatigue, the remaining wires failed plastically. Failure occurred after ~10 years operation. See also Section 4.4.9.	Dynamic riser, production	Applicable to any other flexible riser subject to high fatigue loads in operation.	Detail assessment of local interface loading. Consider implementation of armour inspection systems in high-risk systems to verify initial breaks prior to failure.
2016, 2019, 2020 (x2)	Corrosion of Armours - Major / Catastrophic	Catastrophic failure of four gas injection risers near the seabed due to widespread stress corrosion cracking (SCC) on the tensile armour wires. Pipes were subject to high CO_2 partial pressures in combination with seawater flooding of the annulus. Damage from this corrosion mechanism has also been reported on one other recovered riser and flowline. Failures occurred between 1 and 5 years of operation. Refer to Section 4.4.3 for further information relating to this mechanism.	Dynamic riser, gas	Applicable for specific high CO_2 partial pressure applications with seawater flooded annulus. Susceptibility increases for higher UTS wires.	Subject of ongoing R&D [33], see Section 8.3.
2017	Global pipe defect - Overbend / Pressure Armour Unlock	Smooth bore, high pressure water injection flowline that failed due to pressure armour unlocking leading to large (>45deg) circumferential rupture of the internal pressure sheath after 8 years in operation. Dissection and failure investigation concluded that the unlocking most likely occurred during installation activities. Significant movement of the flowline on the seabed were detected prior to the loss of pressure.	Seabed flowline, water injection	Applicable to smooth bore pipes.	Large scale movements likely indicative of progressive failure mode.

Failure Year(s)	Mechanism	Description	Type of Pipe Affected	Applicability to other Pipes	Mitigations
2017	Tensile Armour Wire Breakage - in / close to end fitting	Failure caused by anchoring system / end fitting mounting deficiencies leading to rupture after ~7 years in operation. It is believed that the armour wires within the end fitting were subject to high bending loads in operation due to the end fitting being in close proximity to the bend stiffener. Three other *Leak* incidents have been attributed to the same / similar mechanisms. End fitting mounting techniques adjusted to mitigate the observed mechanism.	Dynamic riser, oil import / export	Potentially applicable to all dynamic risers where end fitting and bend stiffener are in close proximity.	Adequate armour wire curvature control during end fitting mounting.
2019	Corrosion of Armours - Major / Catastrophic	Combination of corrosion and tensile armour fatigue fracture. Topsides vent open to atmosphere and lead to rupture after 19 years. Repeated shut-downs, temperature variations, atmospheric pressure and limited positive gas diffusion from bore contributed to event.	Dynamic riser, water alternating gas	Applicable to flexible pipe systems with open / breathing annulus vent systems.	Prevent backflow of atmospheric air / moisture into annulus.
2020	Corrosion of Armours - Major / Catastrophic	Catastrophic failure of a gas injection riser near the MWA in a shallow water, benign environment dynamic riser application. High strength, sweet service tensile armour wires were operated in sour annulus environment; failure occurred after ~7years in service.	Dynamic riser, gas	Only applicable where pipe is operated beyond material design intent.	Suitable armour wire material selection.
2020	Corrosion of Armours - Major / Catastrophic	Rupture of a static production riser tied back to a fixed platform. The riser ruptured beneath the topside end fitting during a leak test following 9 years in operation.	Static riser, production	Applicable to flexible pipe systems with open / breathing annulus vent systems.	Prevent backflow of atmospheric air / moisture into annulus.
2020	Tensile Armour Wire Breakage – in main pipe section	Outer sheath breach was identified during installation. Product was recovered and repaired on the installation vessel prior to wet parking (for between 1 and 2 years). Due to practical limitations, the annulus was only partially dewatered prior to repair. Riser failed ~2years after hook-up to the FPSO. Outer tensile armours failed due to accelerated fatigue in combination with corrosion. Corrosion is believed to have resulted from moisture trapped in the tape layers (from initial annulus flooding) and because of an open / breathing vent system.	Dynamic riser, water injection	Specific FPSO turret malfunction led to accelerated fatigue. Open / breathing annulus vent systems and installation damage also contributed to the fatigue-corrosion mechanism.	Adequate repair / mitigation of installation damage. Prevent backflow of atmospheric air / moisture into annulus.
2021	Tensile Armour Wire Breakage – in main pipe section	Water injection riser failure likely due to fatigue failure inside J-tube after 19 years in operation. Inadequate bend stiffener interface design led to a 'rattle' fit and created a fatigue hot-spot within J-tube. Dissection planned.	Dynamic riser, water injection	Specific to the unique bend stiffener interface arrangement.	Adequate design of bend stiffener interface.
2023	Excess Torsion	Distortion of the pipe outer sheath was observed during transpooling of the product from a reel to carousel on an installation vessel. Damage was believed to have been isolated to the outer sheath, however, the pipe subsequently failed during OLT. The failure investigation identified that combined bending and torsion loading during transpooling may have a caused a lateral buckle in the tensile armours. Images of the failure show a shear type failure of the outer tensile armour wires. Failure of the inner tensile armour wire layers / pressure armour layer is believed to have resulted from the induced torsion or shock loading from the outer tensile armour wire layer failure. Damage was also observed on two other flowlines during transpooling (but subsequently passed OLT).	Flowline, production	Potentially applicable to any other flexible pipe	Adequate consideration of transpooling route to avoid excess torsional loading.

4.6 Alternative Damage & Failure Databases

The previous iteration of the JIP, Ref. [13], reviewed alternative sources of flexible pipe damage and failure information (PARLOC, OREDA, and PSA/CODAM). Whilst the objective was to assess if data from these sources could be of benefit to the JIP as additional input, this proved challenging and none of the data was included in the Sureflex statistics. The main barriers in making direct comparisons were;

- The differing emphasis of these other studies, which often focussed on statistics of industry experience relating to the consequences of failure i.e. magnitude and impact of release. In contrast, the Sureflex JIP objective is to define the detailed causes of failures and provide guidance to mitigate them.
- Uncertainties relating to the definitions of damage and failure applied across different studies, making comparisons against Sureflex data invalid.
- Inclusion of failures which were unrelated to unbonded flexible pipes, making comparisons against Sureflex data invalid.

Based on previous reviews and JIP member feedback, a review of the latest OREDA and PSA/CODAM datasets has not been undertaken for this iteration of the JIP. Whilst it had been the intention of the JIP to review the ongoing updates to PARLOC in this iteration, and meetings have been held, the PARLOC update is ongoing and data will not be available until after the completion of the Sureflex JIP report.

5.0 Inspection, Monitoring, Maintenance and Repair Technology Review

5.1 General

This section of the report summarises the results of an extensive review of the range of flexible pipe inspection, monitoring and repair technologies. Detailed tables specific to each technology are presented in Appendix B.

This revision of the JIP extends the technology review to include maintenance and repair technologies and updates the status of available inspection and monitoring technologies presented in the previous iterations (Ref. [13], [15]).

5.2 Format & Content of the Technology Review

The technology review is primarily based on information gathered during a series of five online workshops held in January, February and November 2022. Supplementary information was supplied directly from vendors who were not able to present during the arranged workshops. During the workshops, vendors of inspection / monitoring / maintenance and repair technology related to flexible pipe integrity management were invited to present to the JIP steering committee. Operational experience of these technologies was then shared within the steering committee and along with feedback from non-member operators, forms the basis of the qualitative feedback in this report.

5.3 Workshop Attendees and Post-Workshop Input

The following vendors provided input to the JIP, either as part of the workshops, or during subsequent sessions:

- 4Subsea, Aisus/DXE, Baker Hughes, Balmoral, CRP, FlexLife, FlexTech, GALP, InnetiQs, Kongsberg, NDTGlobal, NOV, OuroNova, Pulse, Simeros, Subsea Energy Solution, TechnipFMC, TechnipEnergies, TRAC, Tracerco, Wood.

Each of the vendor presentations is referenced in Section 11.4 of this document, and where possible the presentations were circulated to the JIP members following the workshop. For vendors that provided input after the original workshops, in general the JIP engaged those vendors directly but utilised the same vendor briefing / format / structure as per the workshops for consistency.

5.4 Technology Readiness Levels (TRL)

A Technology Readiness Level (TRL) is an indication of the "readiness for use" of a specific technology for a specific application. API RP 17N, Ref. [3], defines TRL levels from Level 0 (Unproven Concept) to Level 7 (Field Proven). The key stage definitions are summarised in Table 5.1.

It is not the purpose of the Sureflex JIP to perform detailed TRL assessments of each repair technology / monitoring / inspection tool, rather the TRL level is principally based on the vendor presentations and qualitative operator feedback / experience shared during JIP committee meetings or direct operator feedback. Whilst the technologies reviewed may provide supplementary information for several layers of the flexible pipe design, Figure 5.1 provides TRL levels for the most applicable layer that the technology relates to.

5.5 Industry Take Up

The take up of the technology is scored on a sliding scale from 1 – 5 based on feedback from members of the JIP and from non-member operators who provided their feedback for inclusion within this report.

A "1" on this scale represents a technology or method that has limited or specific applications or is not routinely deployed, whilst a "5" represents a technology or method that is common practice or routinely deployed across the industry. It should be noted that this score does not reflect the appropriateness of a given technology only its relative frequency of use.

5.6 JIP Feedback

The JIP members and non-member contributors provided qualitative feedback on their experience of using the technologies on a sliding scale between 1 and 5. For this measure, "1" is representative of a technology where the operator has either had a negative experience, the results required a lot of interpretation to be understood, or where the technology required significant modifications in order to be deployed for use. A "5" is representative of a very positive experience, clear results that require minimal interpretation, or an off the shelf deployment.

Whilst the feedback scores represent the generalised experience of individual operators, directly comparing competing technologies is challenging as the suitability and appropriateness of an individual technique will depend on the specific failure mechanism, access constraints and individual operator's experiences.

5.7 Summary Matrix of Assessed Inspection, Monitoring & Repair Technology

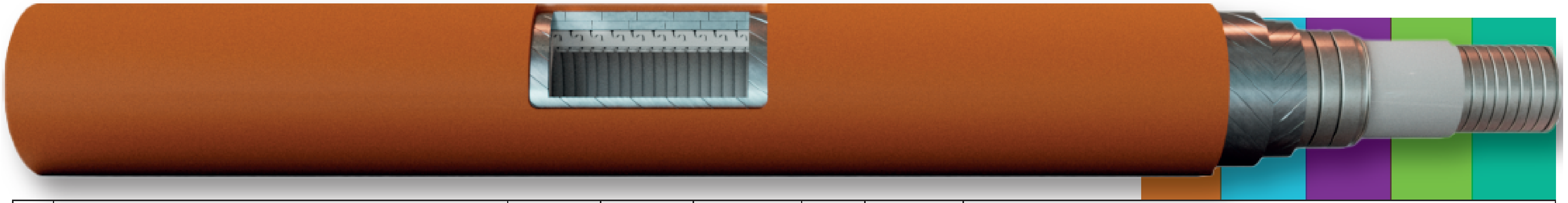
Figure 5.1 provides a summary of the technologies reviewed, identifying:

- Whether the method is used for monitoring, inspection / testing or as part of a maintenance / repair strategy,
- Industry Take-Up (Ref. Section 5.5),
- JIP feedback (Ref. Section 5.6),
- The TRL, specific to which pipe layer(s) the technology applies (Ref. Section 5.4).

The detailed inspection & monitoring technology review sheets / tables are included in Appendix B, and are individually cross-referenced in Figure 5.1.

Table 5.1 Definition of Technology Readiness Levels (TRLs), Ref. [3]

High Level	TRL	Stage Completed	Agreed Definition for Sureflex JIP
Concept	0	**Unproven Concept** Basic R&D, paper concept	Basic scientific/engineering principles observed and reported; paper concept; no analysis or testing completed; no design history
Proof of Concept	1	**Proven Concept** Proof of concept as a paper study or R&D experiments	a) Technology concept and/or application formulated b) Concept and functionality proven by analysis or reference to features common with/ to existing technology No design history; essentially a paper study not involving physical models but may include R&D experimentation
	2	**Validated Concept** Experimental proof of concept using physical model tests	Concept design or novel features of design is validated by a physical model, a system mock up or dummy and functionally tested in a laboratory environment; no design history; no environmental tests; materials testing and reliability testing is performed on key parts or components in a testing laboratory prior to prototype construction
Prototype	3	**Prototype Tested** System function, performance and reliability tested	a) Item prototype is built and put through (generic) functional and performance tests; reliability tests are performed including; reliability growth tests, accelerated life tests and robust design development test program in relevant laboratory testing environments; tests are carried out without integration into a broader system b) The extent to which application requirements are met are assessed and potential benefits and risks are demonstrated
	4	**Environment Tested** Pre-production system environment tested	Meets all requirements of TRL 3; designed and built as production unit (or full scale prototype) and put through its qualification program in simulated environment (e.g. hyperbaric chamber to simulate pressure) or actual intended environment (e.g. subsea environment) but not installed or operating; reliability testing limited to demonstrating that prototype function and performance criteria can be met in the intended operating condition and external environment
	5	**System Tested** Production system interface tested	Meets all the requirements of TRL 4; designed and built as production unit (or full scale prototype) and integrated into intended operating system with full interface and functional test but outside the intended field environment
Field Qualified	6	**System Installed** Production system installed and tested	Meets all the requirements of TRL 5; production unit (or full scale prototype) built and integrated into the intended operating system; full interface and function test program performed in the intended (or closely simulated) environment and operated for less than 3 years; at TRL 6 new technology equipment might require additional support for the first 12 to 18 months
	7	**Field Proven** Production system field proven	Production unit integrated into intended operating system, installed and operating for more than three years with acceptable reliability, demonstrating low risk of early life failures in the field



App B Ref	Inspection / Monitoring / Technology	Monitoring	Inspection / Testing	Maintenance / Repair	Take Up (1-5)	JIP Member Feedback (1-5)	Technology Readiness Level (1-7)						
							Global Riser	Ancillary Equipment	Outer Sheath	Tensile Armour	Pressure Armour	Pressure Sheath	Carcass
B.1	Visual Inspection ROV		X		5	4	7	7	7				
B.2	Visual Inspection Diver		X		2	4	7	7	7				
B.3	Visual Inspection Micro-ROV		X		2	4	7	7	7				
B.4	Visual Inspection Roped Access		X		2	4	7	7	7				
B.5	Visual Inspection ROAV		X		1	4	7	7	7				
B.6	I-Tube Inspection		X		2	4		7	7				
B.7	Laser Measurement		X		2	5		7	7				
B.8	Marine Growth Removal			X	3	4		6	6				
B.9	Environment Monitoring	X			4	4	7			7			
B.10	Offset and Motion Monitoring	X			5/4	4	7						
B.11	Embedded Curvature Monitoring	X			1	N/A	5			5	5		
B.12	Sonar Monitoring (Bend Stiffeners/Risers)	X			1	4	6	6					
B.13	Integrated Fibre Optic Strain Monitoring	X			2	2	6			6			
B.14	Retrofit Bending Control			X	1	N/A	6/5	6/5					
B.15	Temperature Monitoring Inline	X			5	4			7			7	
B.16	Temperature Monitoring Remote	X			2	4		6/5	6/5			6/5	
B.17	Integrated Fibre Optic Temperature Monitoring	X			2	4			7			7	
B.18	Pressure Monitoring Inline	X			5	4				7	7	7	7
B.19	Pressure Testing (Hydro Testing)		X		5/3	3				7	7	7	
B.20	Topsides Annulus Vent Systems Inspection	X	X	X	3	5		7					
B.21	Topsides Annulus Testing		X		5	4			7			7	
B.22	Topsides Annulus Monitoring	X			3	4			7			7	
B.23	Subsea Annulus Testing / Monitoring	X	X		1	N/A			6				
B.24	Vent Port Unblocking			X	1	N/A			6				
B.25	Ultrasonic Testing	X	X		4	4			7	7			
B.26	Electrical Oter Sheath Breach Detection	X	X		1	N/A			5				
B.27	Fibreoptic Armour Wire Inspection (End Fitting)		X		1	N/A				5			
B.28	Clamped Outer Sheath Repair			X	3	4			7				
B.29	Polymer Coupon Monitoring	X			4	4			7			7	
B.30	Bore Fluid Sampling	X			4	5				7	7	7	7
B.31	X-Ray Computer Tomography		X		1	N/A			7	7	7	7	7
B.32	Eddy Current Inspection		X		2	3				7	5		
B.33	Direct Strain Measurement	X	X		2	3				6			
B.34	Magnetic Stress Measurement	X	X		3	2				6/5	4		
B.35	Microwave Inspection		X		1	N/A				5			
B.36	Radiography		X		2	4/2				7/5	7/5	3	7/5
B.37	Acoustic Emission Monitoring - Tensile Armour	X			1	4				7			
B.38	Acoustic Emission Monitoring - Carcass	X			1	2							6
B.39	Internal Inspection		X		2	4							7/6
B.40	Flexible ILI		X		2	3							7
B.41	Flexible Dissection		X		4/3	5	7	7		7	7	7	7

Figure 5.1 Inspection, Monitoring, Maintenance and Repair Technologies: TRL / Take-up / Industry Feedback

Notes: 1. Where two separate numbers are presented for the "take up" or TRL, these either relate to different sub-sets of the inspection technology or to the take-up at different stages of the flexible pipe life cycle. Further details are presented in the Appendix B reference tables.

6.0 Integrity Management Good Practice & Lessons Learned

6.1 General

In this section, sources of good practice on flexible riser integrity management are reviewed, including the relevant industry guidance and standards that exist, the regulatory regime against which the integrity of flexible pipe is managed, and the experiences gained by operators in developing and implementing management strategies.

6.2 Current Industry Guidance

Section 11.1 of the References section of this report identifies the key *Codes and International Standards* relating to unbonded flexible pipe. These are centred around the API specification (API Spec 17J, Ref. [4]) and recommended practices (API RP 17B, Ref. [1]) which were issued at the 4th and 5th editions respectively at the start of 2014. It should be noted that both standards are in the final stages of update / renewal (see also Section 8.2).

In addition to the established API specifications and recommended practices, the suite of codes and standards has been expanded over recent years with the development of a specification and recommended practice relating to flexible pipe ancillary equipment, with the first formal issue at the start of 2013, Ref. [2] and [5].

Other, more general codes, relating to technology qualification (e.g. Ref. [7] and [8]) and life extension (e.g. Ref. [9] [10] and [21]) are also relevant documents in their application to flexible pipes systems and technology.

6.3 Integrity Management Good Practice

Unbonded flexible pipe is a specialist product, with distinct differences to competing pipe technologies. However, historically flexible pipes have often been inspected, repaired, maintained and assessed by personnel with limited specific knowledge or understanding. There is an acknowledgement within the industry that flexible pipe integrity should be managed by individuals and teams that have demonstrable competence and experience in the life cycle of flexible pipe systems.

Section 11.2 of the References section of this report identifies *Other Standards & Guidance* relating to integrity management good practice, including the predecessors to this JIP deliverable, Ref. [13], [14] and [15], as well as the public domain output from the Marintek / 4Subsea / NTNU JIP, "Handbook on Design and Operation of Flexible Pipes", Ref. [16].

Additional reference material is provided in the following sections of this report:

- Section 11.3 *Relevant Technical Papers*
- Section 11.5 *Other References*

6.4 Current Integrity Management Practice

There are many operators who have now established long track records of applying their own interpretation of integrity management, and the predecessors to this JIP deliverable, Ref. [13], [14] and [15] have provided a useful and definitive methodology for demonstrating good integrity practice. These, combined with the improvements in materials and design of flexible pipe, have resulted in the current state of the industry where operators are now largely confident with the effectiveness of their integrity management methods, understanding of failure modes, and are confident in their ability to demonstrate fitness for purpose to the regulatory authorities.

However, despite the track record that now exists, new failure modes are still being discovered e.g. SCC-CO_2 corrosion and corrosion due to open / breathing topside vent systems which had not been experienced when the previous revision of Sureflex was released in 2017. To this extent, it is apparent that continued operator vigilance, industry collaboration and knowledge sharing remains critical and should be maintained. To facilitate this, the JIP uses a standardised template for reporting flexible pipe damage and failure. This is presented in Appendix E, along with guidance on use.

For the more technologically challenging applications (i.e. larger diameter, high pressure, high temperature, harsh environment, heavily insulated), it is common for operators to informally exchange information and experience and there remains a relatively active “community” of organisations and companies that retain a specific capability and dialogue in flexible pipe operation and experience. The vendors are in general supportive of such efforts and, where relevant, have provided guidance to operators where emergent integrity threats have been identified.

6.4.1 Perceived Flexible Pipe Risk Issues

Throughout the JIP, Wood asked member operators what they considered to be their 3 highest integrity threats. These threats have been collated and ranked (based on frequency of response) and are presented in Table 6.1.

These perceived threats are in general aligned with the Damage and Failure experience which is described in detail in Section 4.0 of this report.

Table 6.1 Perceived Threats based on Industry Feedback

Priority	Description
1	Corrosion (including atmospheric vent backflow)
2	Annulus Flooding
3	Blocked Vent Systems
4	SCC-CO_2
5	Fatigue
6	Aged Systems Unsuitable For Life Extension
7	Polymer Sheath Ageing / Degradation Mechanisms
8	Anti-Buckling Tape Degradation
9	Ancillary Equipment Degradation / Design Flaws

6.5 Regulatory & Legislative Regimes

Whilst global operators all follow a similar approach with the key basic intent of managing the risks relating to failures of flexible pipes which could cause safety, environmental, financial, and reputational impacts, there are variations in the regulatory and legislative regimes which are in place in differing global regions. A summary of the main global locations reviewed as part of this JIP are summarised below:

6.5.1 UK

The regulatory body for the UK is the Health & Safety Executive (HSE), with the main aim to secure the health, safety and welfare of people at work and protect others from risks to health and safety from work activity. The HSE regulate health, safety and integrity issues for major accident hazard (MAH) pipelines in the UK (onshore) and UKCS (offshore). Flexible pipelines and risers which fall into the MAH category are included within the "pipelines" definition.

The HSE approach to regulation is based on the (non-prescriptive) goal setting standards set out in the Offshore Installations (Safety Case) Regulations 2015, Ref. [67], and the Pipelines Safety Regulations 1996 (PSR), Ref. [68].

The HSE's Key Programme 4 (KP4) initiative covering ageing and life extension challenges was initiated in 2010. The findings and recommendations from the programme were summarised in an HSE publication, Ref. [69], including those specific to the pipelines component of the programme of work.

6.5.2 Norway

The Petroleum Safety Authority (PSA) is an independent government regulatory body, with the responsibility for safety, emergency preparedness and the working environment in the Norwegian petroleum industry. The PSA regulates the health, safety and environmental (HSE) issues and concerns for all major accident hazard (MAH) pipelines systems within the Norwegian onshore and offshore petroleum industry.

As noted in Ref. [16], the PSA regulations basis with regards to flexible pipe systems is that the operational safety should be equivalent (or better) than that of a comparable steel riser component, as follows:

"*for flexible pipeline systems and pipeline systems of other materials than steel, utilisation factors and any load / action and material factors shall be stipulated so that the safety level for such systems is not lower than for steel pipelines and steel risers*".

The Norwegian Petroleum Directorate (NPD) is a governmental specialist directorate and administrative body. The primary objective is to contribute to the greatest possible value from the oil and gas activities to the Norwegian society, through efficient and responsible resource management. Health, safety, the environment, and other users of the sea are important considerations in this work. Furthermore, the Norwegian Environment Agency is a government agency, whose primary tasks are to reduce greenhouse gas emissions, manage Norwegian nature, and prevent pollution. This includes pollution from oil and gas activity.

6.5.3 Australia

The National Offshore Petroleum Safety and Environmental Management Authority (NOPSEMA) is Australia's independent expert regulator for health and safety, structural integrity (including wells) and environmental management for all offshore oil and gas operations and greenhouse gas storage activities in Australian Commonwealth waters, and in coastal waters where regulatory powers and functions have been conferred. Jurisdictions where powers to regulate are not conferred remain the responsibility of the relevant state or territory. NOPSEMA is responsible for regulating safety and environmental management of offshore petroleum activities through the Offshore Petroleum and Greenhouse Gas Storage Act 2006, the Offshore Petroleum and Greenhouse Gas Storage (Safety) Regulations 2009, Offshore Petroleum and Greenhouse Gas Storage (Resource Management and Administration) Regulations 2011, the Offshore Petroleum and Greenhouse Gas (Environment) Regulations 2009 and other environmental legislation.

These provide a regulatory framework that requires the submission of Environment Plans and Safety Cases for offshore petroleum activities and facilities, including flexible pipelines, for acceptance by NOPSEMA. Additionally, the legislation requires the removal of all equipment, structures and property (including flexible pipelines) when no longer being used.

6.5.4 Gulf of Mexico

The Bureau of Safety and Environmental Enforcement (BSEE) has adopted API RP 75 Safety and Environmental Management Systems (SEMS), Ref. [11] to be released as a mandatory compliance (no longer a recommended practice) in the United States Gulf of Mexico. All operators are now required to develop, implement, maintain and monitor their Safety and Environmental Management systems for offshore operations and facilities including drilling, production, construction, well work-over, well completion, well servicing and pipeline activities. SEMS Program is audited by BSEE or other global organisations.

API RP 75, Ref. [11] addresses the identification and management of safety hazards and environmental impacts in design, construction, start-up, operation, inspection, and maintenance, of new, existing, or modified drilling and production facilities. The SEMS is based on the following hierarchy of program development:

1. Safety and environmental policy
2. Planning
3. Implementation and operation
4. Verification and corrective action
5. Management review
6. Continual improvement

6.5.5 Brazil

The National Agency of Petroleum, Gas and Biofuels (ANP) is the Brazilian government agency responsible for the regulation of the oil sector, bringing together all relevant industry regulations. SSO (operational safety division) is responsible for enforcing the safety regulations, both onshore and offshore. The first safety regulation (SGSO - operational safety management system) was issued by ANP in 2007, which although not specific to pipelines, did address platform risers. In 2015, ANP issued SGSS (subsea systems management system), a specific regulation that encompasses all subsea equipment including pipelines (but excluding Christmas trees).

SGSS personnel are responsible not only to enforce, but to write and update regulations and standards, based on international standards but also taking into account the national experience and engaging the community through workshops and public hearings. SGSS is considered performance based (relying on operator's own risk acceptance and standards), but with some prescriptive points (e.g. life extension, flowlines, types of risk assessment). SGSS also established a dataset (DPP) where operators must provide pipeline features, origin and destination.

The ANP also has responsibilities relating to the investigation of anomalies and accidents, with rules that set the minimum investigation standards, and an incident reporting computerised system (SISO). Brazil is known for having the greatest number of flowlines and has a long history of ultra-deepwater technology development, followed by all challenges related to pre salt production. The regulatory framework is currently under revision, with the ultimate aim to merge SGSO and SGSS (the regulatory updates agenda can be accessed at: https://www.gov.br/anp/pt-br/acesso-a-informacao/acoes-e-programas/agenda-regulatoria).

6.5.6 West Africa

There are no known regulations or authorities comparable with those described above. The philosophies on safe operations are typically “imported” with the operator / contractors corporate guidelines originated whilst working in more established / regulated regions. The assurance of conformity to operators global standards and / or industry codes is generally provided through the operators own internal Technical Authorities.

6.6 Industry Lessons Learned

This section of the report is intended to capture key lessons learned from previous JIPs and recent feedback. It focusses on identifying a series of key technical integrity assurance checks that should be considered in an integrity review. There are numerous industry examples where flexible pipes have become damaged or failed at some point during their life cycle, where the failure initiator can retrospectively be traced back to either an earlier life oversight or a previous industry failure. It is important to consider the risks associated with flexible pipes and the integrity management of them through their entire life cycle. The intent is to identify and manage risk throughout the life cycle so that mitigations can be implemented at the optimal time in the life of the flexible pipe. The key life cycle stages are identified in Figure 6.1.

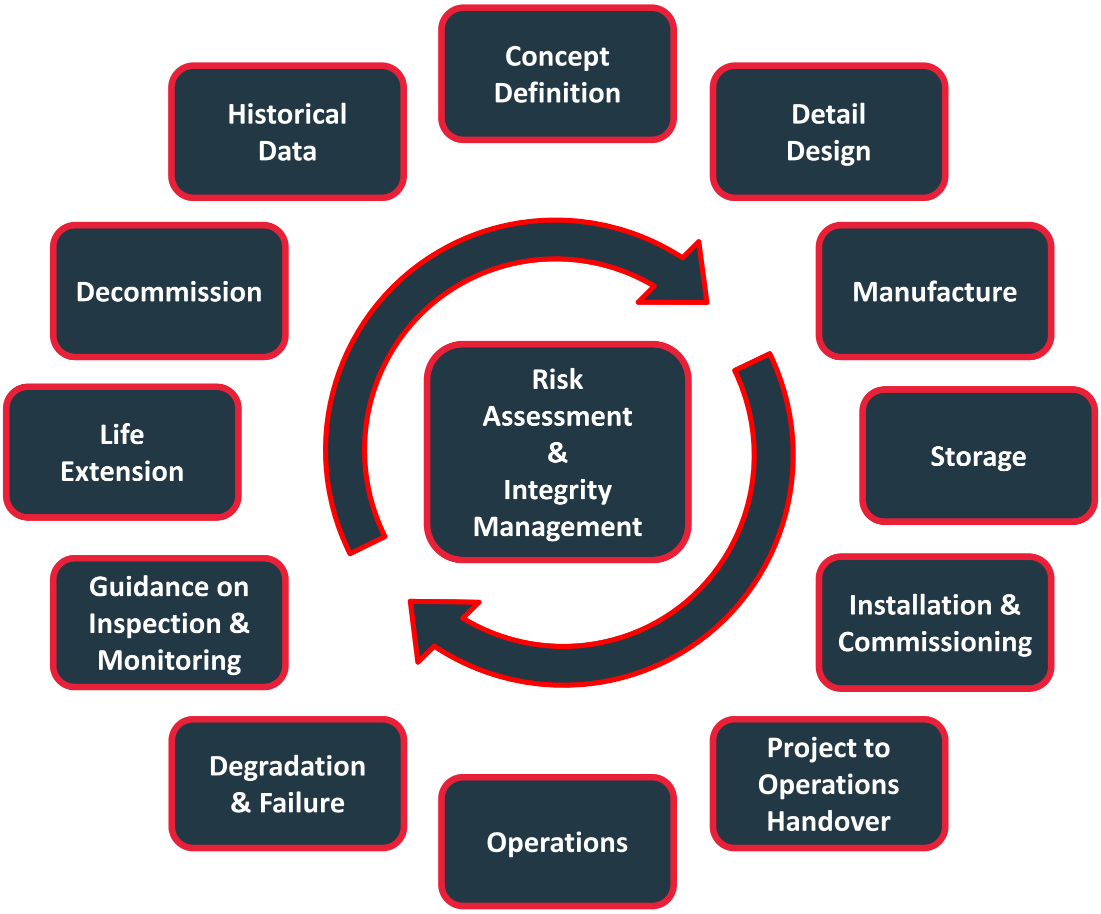


Figure 6.1 Life Cycle Integrity Management

The life cycle stages of the flexible pipe are:

- **Concept / FEED Definition,** ensuring that sufficient design assurance and monitoring capability will be incorporated into the flexible pipe system.
- **Detail Design,** refine the concept definition and develop suitable operating envelopes.
- **Manufacture,** QC/QA plays a significant role in the manufacture of both pipe and ancillary equipment.
- **Storage,** consider all short and long-term storage requirements, and store in accordance with manufacturer's recommendations.
- **Installation & Commissioning,** installation phase often represents the most significant risk of damaging the outer sheath leading to integrity degradation.
- **Project Handover to Operations,** a significant milestone in any project, where careful interface management is required.
- **Operations,** implement, maintain, review and audit at regular intervals an integrity management strategy for the flexible pipe system which includes all ancillary equipment and details boundaries of integrity responsibility and interfaces.
- **Degradation & Failure,** and **Guidance on Inspection & Monitoring,** it is good practice to make use of the best industry data to understand how a flexible pipe can degrade in service and utilise the latest industry guidance relating to inspection and monitoring.
- **Life Extension**, when the operating period approaches the original design life, it is good practice (and in many cases a legislative requirement) to perform a life extension assessment.
- **Decommissioning**, at the cessation of operation of a flexible pipe, bore flushing and pipe recovery / disposal requirements should be assessed.
- **Historical Data**, lessons learned to feed into the next generation concepts and designs, closing the loop on life cycle integrity management.

The following sub-sections provide bulleted lists of key aspects to assess / consider through the main life cycle phases noted above.

6.6.1 Concept / FEED

- Is concept within existing industry experience? Identify key risks and mitigations.
- Fulfil any local legislative requirements relating to identification of major accident hazard threats and mitigations e.g. PSR / MAPD requirements in the UK.
- Sparing philosophy.
- Structural interface definition, e.g. topsides and / or subsea layouts, sizes and clashing risks for ease of installation / retrieval.
- Define requirements for future inspection accessibility, e.g. riser / I-tube / stiffener / interfaces etc.
- Identify requirement for future pigging or line intervention.
- Process monitoring system requirements.
- Consider redundancy in subsea monitoring equipment.
- Consider integrated / built-in monitoring options.
- Robust engineering of configuration or layout, ancillary equipment and installation approach.
- Define overall Integrity Management Strategy (IMS).

6.6.2 Detail Design

- Define statement of requirements, applicable specifications, codes and standards, including life cycle integrity requirements.
- Consider implications of design on every stage of the life cycle of the pipe, including accessibility for in-service inspection and for decommissioning.
- Detailed operating envelopes, including life cycle predictions for design, incidental and limiting operating criteria. This should include offset and mooring design limit states as applicable.
- Operational requirements for monitoring of the flexible pipe system within the topsides specifications / interface areas.
- Ensure riser annulus venting system is constantly and reliably vented to a safe area, which avoids a common vent header and prevents atmospheric backflow. Figure 6.2 presents flexible riser vent system good practice design considerations, and further guidance is given in Table B.20 for ongoing maintenance of annulus vent systems.
- Consider over-sheathing and / or external protection to mitigate flooded annulus threats.
- Assess corrosion-fatigue of riser armour wires in a representative seawater flooded annulus case.
- Assess requirement for project-specific small scale fatigue testing of armour wire materials.
- Assess requirement for prototype testing (Ref. [1], API 17B).
- Ensure dynamic analysis of the riser response accounts for wave frequency effects.
- Agree design load case matrices to assess all life cycle scenarios e.g. installation, hydrotest, shut-in, and operational extreme cases. Consider the particular bending stiffness of the flexible pipe (and bend stiffener), which varies considerably with pressure and temperature.
- Define cathodic protection philosophy and material selection for flexible pipe ancillary equipment.
- Ensure operational constraints / limitations are mitigated where practicable through design (e.g. depressurisation and pressurisation rates, flow velocity, layer-by-layer temperatures etc.).
- Assess ability of the internal pressure sheath in smooth bore pipes to withstand collapse under all operational scenarios.
- Agree acceptance criteria for flexible riser clashing / interference and consider impact testing.
- Ensure marine growth profile and associated mass / hydrodynamic characteristics are reasonable.
- Assess the range of chemical treatments (e.g. inhibitors and scavengers) that may be required through the life of the flexible pipe to ensure material compatibility.
- Assess ancillary equipment design suitability, particularly with respect to installability, integration and long-term performance.
- Assess requirement for integrated / built-in monitoring options.
- Refine overall IMS.
- Consider allocating an operations / integrity engineer to the design team to ensure operability and inspectability are fully accounted for in design.

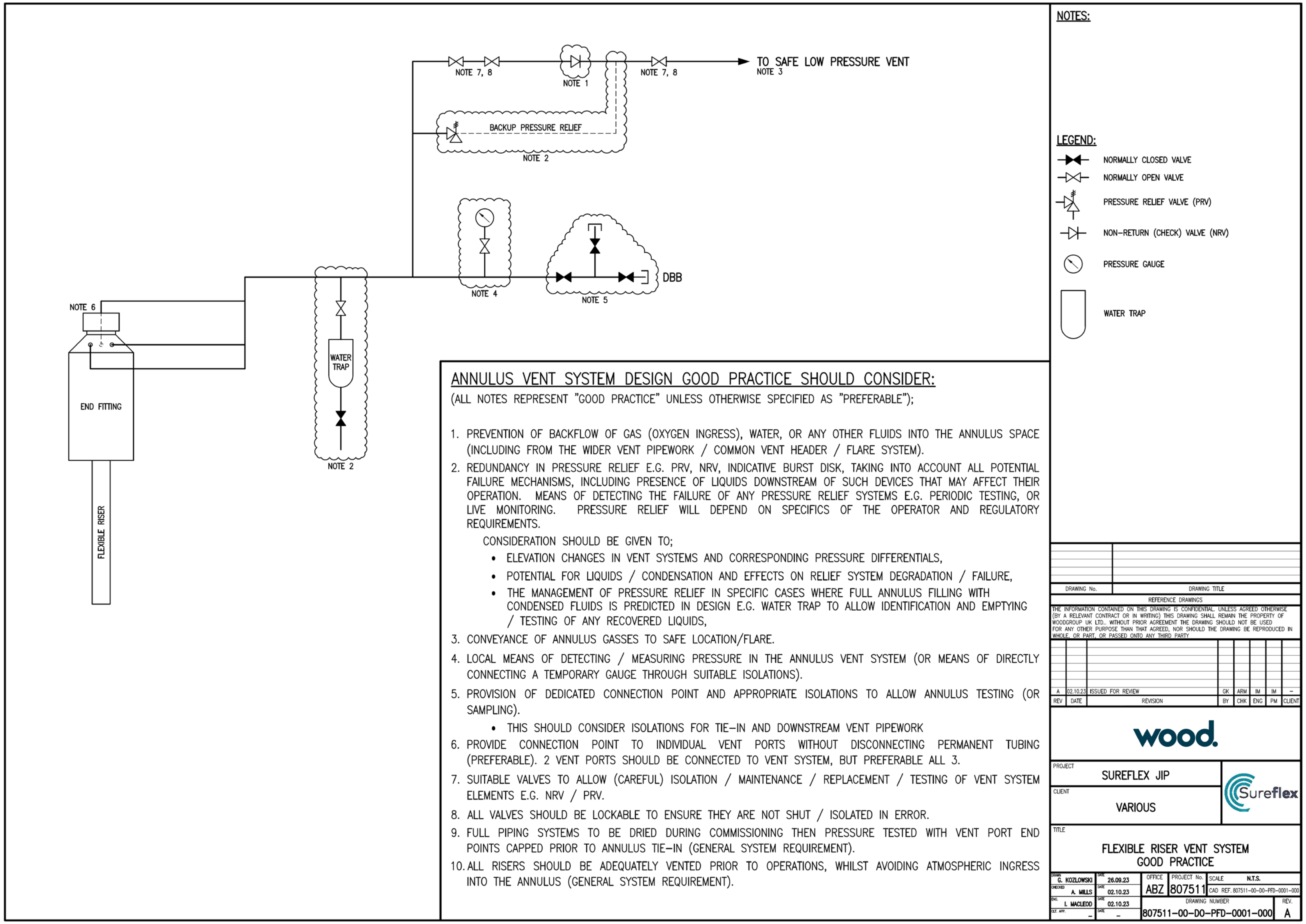


Figure 6.2 Riser Vent System Good Practice

6.6.3 Manufacture

- Agree a detailed manufacturing specification, defining acceptable tolerance limits and NCR process.
- Identify critical areas on the flexible pipes which should be free from welds.
- Document the QA / QC associated with the purchasing and inspection of all raw materials.
- Perform an annulus volume test in the FAT programme to confirm the integrity of the outer sheath and validate the theoretical annulus volume.
- Perform FAT of all monitoring systems, including integrated / built-in monitoring options, if applicable.
- Consider retaining material samples (polymer & steels) from the manufacturing material batches for potential future testing.
- Consider procurement of short samples of the full pipe cross section, to facilitate potential future testing and / or trialling of new inspection technologies if required.
- Assess requirement for vent ports in subsea riser end fittings, e.g. to enable future flushing of the annulus from topsides.

6.6.4 Storage

- Consider both short and long-term storage / verification requirements.
- Define the planned duration between load out and installation and ensure adequate packing.
- Consider the requirements for treating the bore and the annulus of the flexible pipe in storage.
    - For storage beyond ~6 months consider purging the bore / annulus with dry nitrogen.
- Consider the requirements for periodic inspection and testing.
- Assess the requirement for protecting the flexible pipe from UV degradation, temperature extremes or accidental impacts.
- Ensure that pipe ancillary equipment delivered on the product are handled, protected and secured in accordance with approved guidelines, particularly during reeling or trans-spooling operations.
- If wet parking is planned, consideration should be given to the integrity threat from both internal and external corrosion, exposure to physical damage, dynamic stability, external protection requirements, means of recovery / tie-in.

6.6.5 Installation & Commissioning

- Manage interfaces between supplier and installer (if applicable).
- Complete installation analysis, determine allowable sea states, and competently assess deviations.
- Consider application of external protection during the installation phase.
- Use suitably rated installation equipment e.g. tensioners / caterpillar tracks.
- Identify any prior (manufacturing) NCRs and highlight to the installation / operations teams, e.g. sheath repair locations.
- Ensure adequate packing and handling of installation reels, pipes, and ancillaries.
- Perform installation in accordance with procedures and approved management of change process.
- Ensure all operatives are vigilant for evidence of outer sheath damage and are made aware of the implications of damage.
- Assess suspected sheath damage, repair if possible, ensuring qualified repair technicians and offshore repair procedures are available.
- Ensure riser vent ports are plugged to avoid annulus flooding during installation.
- Ensure riser annulus venting system is not obstructed post-installation.
- Perform riser annulus testing to verify condition of the riser external sheath.

- Perform electrical continuity checks on anodes post-installation.
- Perform site acceptance testing of all monitoring systems, including integrated / built-in monitoring options, where selected.
- Retain records of offshore installation NCRs / concessions / deviations.
- Conduct as-built survey of the subsea infrastructure.

6.6.6 Project Handover to Operations

- Project transfer of a flexible pipe system IMS, which is supported and implemented by operations.
- Handover of completed as-built documentation, including baseline inspection data and NCRs.
- Handover of system verification / assurance process and compliance with legislation.
- Establish and document expected operational envelopes (e.g. pressure, temperature, vent rates etc.) to be adopted for each flexible pipe.
- Verify annulus integrity test results as part of the formal handover.
- Consider allocating personnel from the design phase into the operations team to ensure continuity.

6.6.7 Operation

- Actively implement and maintain an IMS. Particular care should be taken during transfer of ownership, to ensure all relevant historic design and operational records / data are transitioned.
- Implement, measure, and assess agreed operational envelopes (e.g. pressure, temperature, offset etc.) for each flexible pipe.
- Monitor and log data from all monitoring systems in line with integrity strategy, including integrated / built-in monitoring options, where selected.
- Monitor the annulus for potential flooding on all risers.
- Ensure the annulus venting systems are fit for purpose, allowing continuous venting and no backflow.
- Establish alarm limits for key parameters and assess excursions.
- Verify compatibility of any annulus treatment fluids prior to use, if required.
- Assess any planned intervention on the subsea infrastructure which has the potential to adversely affect the integrity of the flexible pipe system.
- Implement coupon sampling programme for lines with high risk of thermal degradation.
- Record and compare actual environmental conditions against design limits.
- Repair any site of outer sheath damage on a dynamic riser, assess implications, and consider engaging the manufacturer.
- Where any pipe is considered for use / application in a different service than it was designed for, care should be taken to ensure that appropriate assessments are performed to validate suitability for use.

6.6.8 Life Extension

Industry guidance in generic terms is presented in various standards e.g., Ref. [9], [10] and [21]. The key requirements and common elements for lifetime extension, which are also applicable to re-use, are to:

- Define proposed / extended life, and any planned changes in future operation (service, pressure etc.).
- Assess current integrity based on known inspection, monitoring, and testing records through the life of the pipe (and associated ancillary components which form part of the system).
- Assess future integrity threats / risks, considering the known condition and taking into account relevant industry damage and failure statistics.
- Where applicable, apply appropriate degradation models.
- Identify any repairs / modifications / further assessments (analytical or desktop) that are required to

ensure integrity through extended life.

- Review the current in-place integrity management program (inspection, monitoring, testing), and assess its suitability to mitigate threats in extended life.

6.6.9 Decommissioning

Industry guidance on decommissioning exists in a generic sense and there may be regional and local legislative requirements. However, in general terms, the key points are as follows:

- Consider plans for further use / potential re-use prior to developing a recovery plan, e.g. care of handling approach may vary depending on whether there are plans for re-use.
- Consider threats relating to any fluids in the bore of the pipe, and mitigate through cleaning / decommissioning / recovery program.
- Consider threats relating to trapped pressure / fluid in the annulus, particularly in the case of aged flexible pipes which may not have annulus vent systems and / or where the annulus vent systems may be blocked.
- Assess condition of pipe and ancillary equipment, with particular focus on equipment used for handling / recovery, e.g. was design intent to aid installation only? Can integrity be confirmed etc.? Platform lifting equipment (e.g. pull-in winch / sheaves) may need to be recommissioned, and a winch wire assurance program considered.
- If cutting of the flexible pipe during recovery, care should be given to rigging of cut ends. Chinese fingers or external clamps have a risk of slipping creating a potential dropped object; use of a temporary pulling head may be required.
- Evaluate what level of marine growth removal is required to facilitate recovery.

6.6.10 Historical Data

- Gather and collate data relating to every significant stage of a pipe life cycle, which may be useful learning for the next generation concepts and designs.
- Actively support the industry aspirations of continuous improvement, extension of capabilities, and improved reliability of flexible pipes through gathering and sharing of industry experience.

7.0 Flexible Pipe Technology Development, Manufacturer R&D Efforts

It should be noted that flexible pipe manufacturer JIP members did not directly share their respective internal R&D efforts as part of the JIP scope. Instead, consistent with predecessor Sureflex reports, this section only considers public domain information from a range of sources which are briefly summarised below;

1. Carcass layer design

   The manufacturer-led development and independent qualification of anti-FLIP carcass insert layers is a significant achievement in recent years. Whilst there is currently limited operational experience of pipes in service, an increasing number of pipes incorporating a carcass insert design have been awarded / delivered. The inserts are designed to prevent the occurrence of FLIP by shielding the recesses in a conventional carcass profile, and as a consequence also reduce pressure losses in the pipe. It is likely that the range of available material grades, carcass and carcass insert wire geometries will continue to expand as the take up and deployment of this technology continues to grow. Refer to Section 4.1.2.1 for further details.

2. Polymer materials

   The development and qualification of new internal pressure sheath material grades remains an ongoing effort to extend temperature, fatigue and pressure performance limits and to achieve improved cost competitiveness. In the last 5 years, particular research into increasing the temperature resistance of PE based polymer grades has led to all of the manufacturers qualifying new materials (i.e. ITPE) in order to reduce the reliance on higher cost PVDF grades. In addition, new grades of PVDF have been qualified that negate the requirement for multi-layer sheaths therefore mitigating a number of failure mechanisms associated with these designs, ref Section 4.4.4.2.

   The flexible pipe manufacturers continue to develop new materials, which are more environmentally friendly in response to, and to keep ahead of, new and emergent environmental regulations.

3. Armour wire design

   Qualification of non-metallic and other composite materials for use as tensile and pressure armour wires are ongoing developments, primarily to reduce the top tension interface loading in deep and ultra-deepwater applications. An additional driver for technology development in this area has been the emergent SCC-CO_2 failure mechanism (ref. Section 4.4.3), where non-metallic materials offer advantages over traditional carbon steel armouring in terms of corrosion susceptibility and reduced permeability compared to traditional flexible pipe.

   The qualification of more corrosion resistant metallic armour wires and significant R&D work in defining threshold conditions for the SCC-CO_2 failure mechanism is an ongoing focus area, see Section 8.3.

   In addition, some manufacturers continue to develop and offer flat-strip (non-interlocked) pressure armours for more benign applications.

4. Flow assurance

   Flexible pipes with improved thermal performance (and monitoring) continue to be an area of research, including developments in flexible pipe insulation, the provision of active heating, and integrated temperature monitoring.

5. Integrated inspection and condition monitoring technology

   All manufacturers have developed various integrated and non-integrated monitoring solutions, and continue to do so. Further information presented in Section 5.0, Section 9.4, and Appendix B.

6. Applications expansion in the energy transition

   Manufacturers continue to develop and qualify flexible pipe for expanding product application, including in the energy transition markets for CO_2 and H_2 transport / sequestration.

8.0 Other Relevant Joint Industry Projects (JIPs) / Forums

8.1 General

This section of the report summarises a number of other JIPs / initiatives relating to flexible pipe technology and integrity management. These JIPs are at varying stages, some having been established and run through several phases over an extended period, whilst others are at the proposal stage. The intent however is to gather and share knowledge relating to all recent / relevant joint industry projects and initiatives.

8.2 API Renewal Programs

Whilst not a Joint Industry Project as such, the periodic renewal of key API Specifications and Recommended Practices involves a large community of industry stakeholders. The ancillary equipment documents (API Spec 17L1 & API RP 17L2) were updated and issued as 2nd Editions in June 2021. The updates to the main flexible pipe documents (API Spec 17J & API RP 17B) have been ongoing since 2020 and are scheduled for completion in 2023.

8.3 Stress Corrosion Cracking (SCC) CO_2 JIP

The SCC-CO2 JIP is in the early stages of a 3.5year planned program of work to gather, consolidate, and identify technical data and information about the impact of the CO_2 Stress Corrosion Cracking failure mechanism on unbonded flexible pipe. The JIP is managed by Simeros, and all three major pipe manufacturers are members.

The program aims to promote qualified discussion forums to exchange technical data, define efficient testing methods and qualification requirements. Based on that, efforts will be directed towards establishing reliable design practices and safe limits required to qualify API Spec 17J flexible pipes operating in CO_2 rich environments and assist the industry in defining effective risk management strategies for their assets.

8.4 Corrosion-Fatigue JIP

In co-operation with SINTEF Materials and Chemistry and IFE (Institute for Energy Technology) Department of Materials and Corrosion Technology, MARINTEK was running a JIP with the aim of developing a basis for fatigue design of armour wire in which the effects due to the chemical environment in a pipe annulus are taken into account. The project was started in 2001 with Phase I and was completed with Phase VI, in 2020.

Testing was carried out on tensile armour wire in air, as well as in aqueous environments with CO_2 and/or H_2S at various partial pressures. Standardised test methods and testing protocols were developed. In addition, S-N curves were obtained for more than 60 different combinations of material grade, environmental composition and loading parameters, mainly covering a range of 10^5 - 10^7 cycles to failure. Some tests have been run up to 10^8 cycles.

The technical focus was very much the same as when the JIP started, but the last Phase (Phase VI) included testing of corroded armour wire from risers retrieved from service. It also included more work on the annulus conditions and how to reproduce these conditions in the tests. The JIP has been documented in a number of technical papers through the duration of the project, most recently in OMAE 2009-80262, Ref. [30].

8.5 Polymer JIPs

The Rilsan User's Group (RUG), comprising operators, manufacturers, and raw material suppliers, developed guidance on the use and operation of PA11 in flexible pipe applications, concentrating on the use of PA11 in the internal sheath of flexible pipes. In particular, ageing mechanisms and associated loss of mechanical properties was investigated. The recommendations of RUG were published as a technical report, Ref. [6].

In the interim period further work has been performed to refine ageing models for polyamides and other materials. The JIP SESAM PA11 (2008) was tasked to develop guidance and a new ageing model for polyamides subjected to exposure from organic acids. The result of this JIP showed that water soluble organic acids enhanced the PA11 degradation, Ref. [16].

The Q-PA-FLEX JIP, managed by 4Subsea and completed in 2021, has prepared an addendum to API17 TR2 with recent learnings & experiences (pending publication). The JIP focussed on; understanding the reasons for observed scatter in PA ageing modelling, laboratory testing, field experiences, loss of ductility, and the effect of organic acids on service life.

8.6 Prediction of Flexible Riser Annulus Environment JIP

The Flexible Pipe Permeation JIP was completed by DNV in two phases between 2017 and 2021. This has created an independent permeation model to predict the composition of the annulus environment. In addition to typical gas permeation, the model studied the consumption effect of steel wire corrosion to predict the annulus environment. The model is intended to be used to define the key parameters that could influence stress corrosion cracking, sour fatigue and fracture performance of steel armour wires. The Flexible Pipe Permeation JIP authors intend to validate the models with additional experiments in future phase work.

8.7 Flow Induced Pulsation (FLIP) Studies

The following JIPs / studies addressed flow induced pulsation issues on flexible pipes and the associated vibration-induced fatigue threats.

- OTC-26346 Singing Mitigation in Corrugated Risers by Liquid Injection, Ref. [35].
- PVP2014-28533 Singing Mitigation in an Export Riser via Liquid Injection: A Field Case Study, Ref. [36].
- Guidelines for the avoidance of vibration induced fatigue failure in Subsea Systems, Energy Institute, Ref. [37].
- OTC19904 Flow Induced Pulsation due to Flexible Risers, Ref. [38].
- OTC18895 Internal Flow Induced Pulsation of Flexible Risers, Ref. [39].

Further guidance relating to FLIP threats and mitigation are given in Section 4.1.2.1 of this report.

8.8 Safe and Cost Effective Operation of Flexible Pipes JIP

As noted in Section 6.3, this JIP ran from 2011 to 2013, the key deliverable of which is the publicly available "Handbook on Design and Operation of Flexible Pipes", Ref. [16]. This Norwegian-led JIP (Marintek / 4Subsea / NTNU) includes an extended and updated revision of the 1992 handbook (FPS2000 project). The 2017 edition includes volume 2 with case studies and appendices.

8.9 Qualification and Guideline on Inspection Technologies for Flexible Pipe

The Pipeline Research Council International (PRCI) completed a project in 2021 to qualify inspection technologies for flexible pipe integrity management. The project objective was to test and qualify several NDT inspection tools for flexible risers and flowlines. The focus of the project was to perform a quantitative evaluation of performance of inspection tools. Twelve inspection tools that are based on four underlying technologies (Ultrasonic, Electro-Magnetic, Magnetic, and Radiography) were tested in the program.

8.10 Flex Pipe Corrosion Monitoring JIP

The 4Subsea flexible pipe corrosion monitoring (FPCM) JIP ran from 2014 to 2017, with the key objectives to:

- Increase the knowledge of corrosion mechanisms for flexible pipes in operation, with intact and damaged external sheath,
- Link integrity management activities to experienced failures and observed corrosion status after pipe dissection,
- Improve tools and methods used for assessing corrosion scenarios, repair and monitoring possibilities.

The FPCM JIP was continued in two R&D JIPs;

- FPCM-II coordinated by 4Subsea, where a best practice for corrosion assessment of flexible pipes was prepared. FPCM II was completed in 2022.
- KFC-1 coordinated by IFE and NTNU, where steel cracking in flexible pipe armouring is addressed. A follow up, KFC-2, is planned to start in 2023.

The FPCM JIP have developed a paper on flexible pipe corrosion assessment, which was presented in Ref. [44].

8.11 FlexShare

FlexShare started as an initiative under the NOROG umbrella (Norwegian oil and gas association, consortium of operators working to serve the interests of the oil production industry). It started as a JIP (2016-2017) involving operators of flexible pipes. The overall objectives are to:

- Facilitate efficient experience sharing related to flexible pipes between operators,
- Update the web-accessible database of flexible pipe events,
- Provide a forum for further enhancements and efficient collaboration.

8.12 Riser End of Life JIP

This historic Flexlife JIP, Ref. [70] was discussed in more detail in the last Sureflex revision, Ref. [13]. The JIP investigated the residual life in aged dynamic risers from one project and assessed inspection technologies. The polymer had degraded to a level that was generally expected for pipes in this application but was not approaching a failure limit. For the tensile armour wires, a limited number of comparative fatigue tests indicated that the fatigue strength of the “used” wire samples was reduced by ~50% when compared to that of the control samples.

8.13 Sureflex Network

The Sureflex Network will follow-on from the completion and finalisation of this report, as per the JIP proposal from March 2021, Ref. [66]. The Network will meet periodically and continue the active sharing of experience and expertise across the JIP stakeholder / steering committee group. The Network will maintain the damage / failure databases with any new events (shared by either JIP stakeholders or from external parties) which will be continuously shared with members for consideration of the potential impact on their own flexible pipe inventory. In addition, a further deliverable will periodically present an update of the damage and failure events data within this main JIP report.

The key areas of focus for the Sureflex Network are to:

1. Share integrity lessons learned and good practice,
2. Maintain and share flexible pipe integrity / damage / failure data,
3. Share information on inspection techniques (new information, and emerging technology),
4. Periodic re-focus on key issues, driven by member feedback.

9.0 JIP Workshop Sessions, Focus Areas

9.1 General

This section presents a summary of the workshop sessions hosted throughout the course of the JIP.

9.2 Digital Twins (15th September 2021)

The first workshop session explored the current usage and understanding of digital twins in a flexible pipe system context within the JIP membership. The format of the workshop was a combination of presentation slides supplemented with live Slido™ polling to a range of questions on this topic. A total of 35 workshop attendees responded to the Slido polling.

It is apparent that a "Digital Twin" (DT) can be interpreted differently depending on the individual. At a basic level, a DT may be defined as virtual model of a physical object, whilst a more advanced DT serves as a real-time digital counterpart that utilises real world monitored inputs to support system or process optimisation. An opening question on the use of DTs indicated a narrow majority did not consider that their current flexible pipe integrity management made use of DTs. Wood argued that base level DTs are an essential and established tool for flexible pipe systems and cited examples of cross section design and permeation modelling tools in addition to the global modelling programs routinely used for dynamic riser system design and through life cycle integrity assessments. One contributor agreed that such 3D global models also represent highly effective communication tools.

However, in practice there is limited practical opportunity for DTs to be used to optimise operational performance, i.e. the physical installed pipe system is fixed, therefore the objective is more commonly to track condition, assess the impact of operational anomalies or changes (both external and internal to the pipe) and ultimately to support timely decision making. It was additionally reported that such models or DTs are in general well trusted and are often updated in response to observed changes in operational conditions as applicable. Follow up discussion highlighted Ref. [22] as a useful reference in describing the requirements for qualification and assurance of DTs.

The workshop attendees expressed an expectation that DTs, in some form, will see increased usage in the future, however, it was recognised that implementation will evolve at different rates across different assets and operators. Furthermore, good DT practice will vary depending on the age of a particular asset. For all flexible pipe systems, reliable monitoring and logging of operational data remains a key objective as inferred or assumed operational history can degrade confidence in integrity assessment. As such, it was noteworthy that no respondees rated their operational data management as highly effective, with over a quarter reporting this as poor. Hence, this aspect remains an ongoing challenge for DT reliability.

One clear opportunity for increased use of DTs in the context of flexible pipe systems relates to integrated monitoring technologies, involving sensors located within the pipe to measure strain, temperature or curvature / tension variation in service. Workshop attendees reported that a minority had implemented such technologies within their flexible pipe assets citing the upfront CAPEX, resistance from the operating asset and perceived additional effort to maintain and manage such equipment as the key barriers. However, a minority of respondees (<25%) reported a negative experience with instrumented flexible pipes, highlighting some practical difficulties in data sharing as their key concern. One flexible pipe vendor described an intention to adopt an incremental approach in order to limit upfront cost, i.e. to implement a sensor housing that provides optionality and an ability to adapt data monitoring in service.

In summary, the workshop confirmed the ongoing reliance on a form of DT, i.e. virtual models / tools in combination with monitored operational data, as fundamental to good practice flexible pipe integrity management. The challenge of flexible pipe integrity is focussed on establishing confidence in the current condition, however, the adoption of smarter and more digitally intensive technology that has the potential to provide this has been gradual to date and varies widely across different operators and assets.

9.3 Regulatory Expectations (7th February 2022)

This workshop session focussed on exploring and reviewing regulatory expectations, and how they vary (or are similar) in different global regions. The session included presentations from each of the member regulator organisations (NOPSEMA, PSA, HSE, and ANP) on specific points, and there was some time for follow-on discussions. Efforts were made to gather input from additional regulatory bodies outside of the JIP membership, although these were unsuccessful.

The regulators presented on the following common points / topics;

- Primary regulatory approach
- Basis of approach
- Level of involvement (regulation) through asset life cycle stages
- Incident reporting protocols / requirement

Table 9.1 presents the key points relating to the regulatory expectations, along with any standout / additional / different requirements in the final row of the table. Further information relating to regulatory regimes is given in Section 6.5 of this report.

Table 9.1 Key Points Relating to Regulatory Expectations

Parameter	ANP - Brazil	HSE - UK	NOPSEMA - Australia	PSA - Norway
Primary regulatory approach	Subsea Systems Operational Safety Management Gerenciamento de Segurança Operacional de Sistemas Submarinos (SGSS)	Pipeline Safety Regulations (PSR) 1996	Offshore Petroleum and Greenhouse Gas Storage Act 2016 (OPGGS)	PSA Framework Regulations
Basis of approach	Safety management with prescriptive items	Goal setting, Safety Case (facility) plus MAPD	Goal setting, non-prescriptive, Pipelines Safety Case	Goal setting, specify level of safety (but not <u>how</u> to achieve)
Asset life cycle stage involvement	Design, Operate, Maintain, Re-use regulations, Decom.	Design, Operate, Maintain, Decom- safety aspects	Design, Operate, Maintain, Decom-default full removal	Design, Operate, Maintain, Decom-consent required
Incident reporting protocols	Incident reporting manual & systems	Damage, failure, release which <u>could</u> cause injury or shutdown >24hours	Death, injury, LTI>3days, dangerous occurrences (including releases)	Hazard / <u>potential</u> of death, injury, pollution, or safety impairment
Common to all?	A common focus on preventing (primarily hydrocarbon) leaks and accident prevention			
Anything standout / additional / different?	Defined requirement for R&D investment, More prescriptive focus		Default for decom. is full removal	Lifetime extension application submission 1year before expiration

9.4 Integrated Monitoring (28th June 2022)

The application of integrated monitoring of flexible pipe systems has developed in recent years, and has been quantified in the preceding and current phases of the Sureflex JIP (see also Section 5.0, Figure 5.1, and related tables in Appendix B; e.g. Table B.11 / Table B.13 / Table B.17 / Table B.33 of this report). Whilst the technology associated with integrated monitoring from the main flexible pipe vendors varies and continues to evolve, the vast majority of installed flexible pipe systems do not currently have integrated monitoring systems. This is primarily due to the fact that the technology cannot be retrofitted, though at least one supplier can supply a conduit / connections for subsequent installation of some monitoring systems at a later stage.

During this workshop, one of the supplier members of the JIP presented on their available technology / techniques, and there was subsequent discussion across the JIP membership. Several of the current integrated monitoring systems utilise fibre-optics embedded within the flexible pipe structure, and are typically restricted to riser applications where access to the top end fitting allows connection / transfer of data, and include systems for both strain and temperature measurements (further details in Table B.13 and Table B.17 respectively).

Integrated fibre optic strain monitoring systems are currently restricted to the top-zone of the flexible riser (which is typically subject to the most onerous extreme and fatigue loading) based on point measurements utilising Fibre Bragg Grating (FBG) sensors. These are either embedded within grooves on the edge of armours or within discrete conduits within the annulus, and normally include additional monitoring fibres for redundancy. Such systems can be used to assess accumulated fatigue damage (in combination with appropriate SN curves) and tensile wire breaks (even from unmonitored wires through stress redistribution).

Temperature monitoring systems are typically distributed over the full length of the monitored riser. The differences in localised temperatures under bend stiffeners / buoyancy module clamps can also be used as an indicator of ancillary equipment displacement / anomalies, and event detection can identify annulus flooding / sheath breaches. The technology has the potential to reduce / optimise more traditional visual inspection approaches.

9.5 Re-Qualification and Re-Use (6th June 2023)

The objective of the final JIP workshop session was to establish the extent and experience of flexible pipe re-use and / or re-qualification in practice. Good guidance on re-use requirements is presented in Ref. [1] whereby the content has remained effectively unchanged since the 3rd edition published in 2002. However, there are limited documented examples of successful re-use and in most cases the anecdotal experience relates to either reconfiguring or relocating of subsea jumpers within a particular asset, or alternatively as a readily available replacement in case of integrity concerns on an adjacent flexible pipe. The JIP is not aware of re-use experience with longer flexible flowlines, citing uncertainty of pipe layer-by-layer condition and potential for damage during recovery as the key risks.

A JIP member presented a specific example of a refurbished dynamic flexible riser that was found to have experienced through external sheath abrasion inside the host facility guide tube bellmouth six years after installation. The operator identified a seawater flooded annulus through an annual vacuum testing program and subsequently recovered the riser to assess potential for re-use. Despite a significant area of missing sheath, there was negligible damage to the outer tensile armour wires and a decision was made to refurbish the riser. This involved stripping the external sheath layer, allowing the annulus to dry, adding an anti-buckling tape (resulting in a small increase to the pipe outer diameter), re-sheathing, re-termination and testing. The riser orientation was also switched such that any residual fatigue damage at the bellmouth location is shifted to the static seabed end.

In addition, the buoyancy modules and clamps were also refurbished, which necessitated sanding down the new external sheath at the buoyancy clamp positions. Since the riser was re-terminated, the dynamic configuration had to be re-engineered to accommodate the reduction in riser length and new ancillary items including bend restrictors, a hold down tether and wear protection elements were procured. This spare riser system is now deemed fully refurbished and is considered ready for deployment if required by the operator.

Wood shared experience of a 6-inch, 206m long dynamic riser that was recovered after 3 years operational service in a North Sea steep-wave application and then re-configured for a shallow water dynamic riser application in another offshore region, linking a fixed wellhead platform with an FPU. In this example, the riser was not re-terminated and instead the fixed length determined the FPU location. A number of buoyancy module assemblies were re-used as were the topside and subsea bend stiffeners as shown in Figure 9.1. Wood is aware of another North Sea example, Ref. [34], where the flexible pipes were recovered after less than 2 years service and also sold to a third party for re-use in another region. In both cases, the re-use potential arose from underperforming field reservoirs and premature cessation of production, although there is no documented feedback from the re-use application.

Other re-use examples include offshore re-termination and change of service of a damaged North Sea riser [25], change of pipe service following FAT failure or failure in service, and examples of pipes being re-terminated onshore after incurring installation damage and subsequently sold onto a third party. Each of these cases represent opportunistic experience rather than planned re-use.

A discussion on barriers to re-use agreed that any potential benefits to a project are almost always outweighed by risks relating to uncertainty on the pipe and/or ancillary component condition, potential for damage during recovery and requirement for onshore inspection. Furthermore, there is generally no motivation to re-use in terms of the project economics or schedule of a typical development project, given the relatively short lead time to engineer, procure and install a bespoke flexible pipe system. Recovery of flexible pipes for re-use requires to be properly engineered and executed using a capable vessel with adequate treatment/cleaning and storage provision, the cost of which may exceed the cost of procuring new equipment. One member shared experience of recovery requiring excessive time for deepwater pipes to avoid outer sheath ballooning due to slow residual annulus pressure bleed off rates. The same member reported wide variation in recovered GRV performance after an extended period of operation.

The one exception to the above re-use experience relates to early production systems or extended well testing, where a member reported re-use as a more commonly adopted practice. Re-use of flexible pipes for such applications is more readily justifiable given the limited intended time in service and from an economic perspective where re-use can accelerate the schedule to first production.

In summary, the main practical challenges of re-using flexible pipes are related to uncertainty of the pipe condition and risk of handling damage during the recovery, transpooling, storage and reinstallation phases. Achieving confidence in the pipe condition requires reliable recording of pipe operational parameters, primarily internal pressure, temperature and bore fluid composition. It is concluded that flexible pipes can be safely re-used, however, to date the limited examples relate to either short term applications or relatively unaged pipes.

Figure 9.1 Dynamic Flexible Riser Re-use

10.0 Operator Information Exchange

During the Sureflex JIP, members presented on their specific integrity management challenges / interests (with wider community discussion / sharing). Whilst these meeting sessions were not recorded and the slides typically not circulated / shared, this section of the report summarises the lessons learned / key points. The intent was also to highlight "good news" stories e.g. pipes that have been recovered prior to failure as a result of good monitoring measures, or where pipes have been recovered and the condition was better than expected. Table 10.1 summarises the (desensitised) points from the presentations. In addition, key points from equivalent sessions which took place in the previous phase of the Sureflex JIP are presented in Section 9 of Ref. [13].

Table 10.1 Lessons Learned and Key Points from Information Exchanges

Workshop / Meeting	Lessons Learned / Key Points
30/11/2021	<u>Riser annulus monitoring system issues and impact upon riser integrity</u> • Bug identified where if the system crashed without an alarm the solenoid valve isolating the annulus stayed in the last position and did <u>not</u> automatically fail-safe in an open position, leaving the riser annulus at risk of over-pressurisation. Software / hardware updates rectified the issue. • Liquid plug (condensed annulus fluid) at sag bend on some risers. Hypothesis is that the increased annulus pressure (1.8barg at annulus topsides) may increase condensation rate.
30/11/2021	<u>First Use of UT Pigging for Evaluation of Carcass Condition after a Hydrate Event</u> • Case study using UT pig to map carcass profile / pitch / extension. Measurements were taken at 128 points around the circumference with an axial interval of 0.75mm. • A differential pressure of 82bar was experienced across a hydrate plug (although the exact location in the flexible riser / rigid pipe system was not clear). In-house calculations indicated that this pressure was expected to cause damage, if experienced in the flexible riser. • From the topsides, the inspection tool could only reach the sag bend (not the hog bend) and did identify a step change in the carcass pitch at ~200m into the inspection length, though this could not be explained from review of as-built data, however no damage / tearing was identified.
02/12/2021	<u>Anchor Drag Incident and Damage</u> • Case study experience of a vessel anchor drag across a 4inch gas pipeline and a larger water injection line. Gas pipeline was non-operational, but pressurised at 53bar, and the outer sheath was torn and external damage identified. The WI pipeline had a larger tear in the outer sheath. • Structural integrity tests performed successfully at 1.25times design pressure for 24hours with dye and inspections during tests. Test pressures were 280barg / 350barg for the separate lines. • Additional water alternating gas line installation provided some operational mitigation, and increased future inspections and re-assessments are planned.
26/05/2022	<u>Riser Failure, Damage Experience and Integrity Management Implications</u> • Catastrophic riser failure following large number of armour wire fatigue failures, driven by local contact loading at bend stiffener connector. • Significant assurance / management implications on remaining risers; differing results from magnetic stress measurement / acoustic monitoring systems, leading to additional inspections (double wall digital radiography). • Subsequent monitoring (initiated following riser failure) on a separate riser indicated first recorded wire fatigue break after 13years service, with an accelerating rate of events over the following ~1.5years, and a total of 19 wire breaks (35% of all wires in armour layer) upon recovery thereafter.

Workshop / Meeting	Lessons Learned / Key Points
20/09/2022	Operator learnings on polymer crazing in high pressure PVDF pipe • Case study relating to crazing in high pressure (15ksi) pipe qualification. Noted that crazing is complex challenge, but is limited to very high pressure (and PVDF specifically) applications. Critical load cases were FAT (19.5ksi), OLT (offshore leak test) and SIT (structural integrity test, 18.1ksi), particularly where reverse bending strain had been experienced in the manufacture phase.
21/09/2022	Water injection smooth bore jumper end fitting failures (3 off) • Jumper failures only (not risers) where sealing of the internal and intermediate sheaths varied. A gap in the end fitting body / cover opened after 2-3years operation, leaks occurred ~1year later. • Original design utilised a single sealing arrangement for both sheathes, whereas updated / current designs mitigate the threat. • Rapid depressurisation / cycling was a significant factor in the failures (~400bar/minute). New common structure was subject to 100 test cycles at a depressurisation rate of 150psi/second (equivalent to 620bar/minute).
06/06/2023	Re-use of a flexible riser • Case study of riser which was installed 2010 and annulus flooded in 2015 (additional testing confirmed breach at bellmouth transition, via abrasion). The additional / external anti-abrasion layer was ~5metres too short to protect the bellmouth area which would likely have extended the period prior to flooding. Recovered to shore in 2016. • Significant onshore inspection (<0.2mm corrosion in exposed area) and repair (outer sheath removed, re-sheathed, and re-terminated). New ancillaries (tethers / clamps, restrictors) required due to larger diameter (additional anti-buckling tape layer).
06/06/2023	Managing in-service risks / inspection • Operator approach shared on managing maintenance; Corrective (clamp repairs), Preventative (GVI, annulus test, PA coupons), Predictive (incident based assessment, NDT, FFS, life extension). • Example #1, static riser exits I-tube 60m above seabed in 400m water depth. Magnetic stress inspection indicates 3 to 4 wire breaks in this area due to perceived corrosion threat. UT inspection to verify annulus condition and re-test magnetic stress planned. • Example #2, riser outer sheath tear (2metres length) on external turret FPSO in splash-zone. Repair clamps installed (3off over 15years, challenging to seal annulus leaks). Eddy current inspection indicates no corrosion risk, but corrosion-fatigue threat exists, assessments ongoing.
07/06/2023	Commissioning lessons learned • Pig tracker lost from damaged commissioning pig and left in sag-bend of riser. Recovery project over period of 2 weeks (which included 1 week delivery of bespoke recovery tool). • The tracker was recovered by deploying a bespoke pig with a concave nose to "scoop" up the tracker and retrieve to surface. Care needed to engineer / test / assess solution options. • Contingency camera tool was also sourced, but given the recovered tracker was undamaged, the threat of carcass damage was deemed unlikely so camera was not deployed.

Workshop / Meeting	Lessons Learned / Key Points
07/06/2023	Risk based inspection and new possibilities • Operator approach to RBI, sharing experience on new tool applications including; retrofit direct strain measurement of armour wires, computer aided (graphic assessment) of torsion / pipe twist, magnetic stress inspection, and various annulus condition management systems. • Noted that to date there was a lack of industry-wide recommended practices relating to ongoing operation of damaged pipes. Significant investment and efforts ongoing to understand pipe residual strength and rate of progression to failure, including dissection programs. • Operator also acknowledged long-standing challenge of flexible pipe layer inspectability, and the need for improved integrity management technologies, driven by emergent threats / risks.
07/06/2023	Bend stiffener properties in-service • Experience of testing the material properties of 4 recovered bend stiffeners from a single asset (after 10 to 14years service), all of which showed significant deviations in the elastic modulus / stiffness of the polyurethane. Reductions in the range of ~45% to 60% were observed compared to the original design mean and as-built samples, which were based on thin samples from the supply batch at that time. Identified as contributory factor in fatigue failure of one riser and degradation of others. • Discussion during the workshop indicated that it was unknown if the reduction in elastic modulus / stiffness had occurred in service, or whether the properties may have been low from start of operations. Assessment and discussions are ongoing with the supplier. Also noted that there was an updated process for as-built testing / sampling of materials. • Further discussion supported the aspiration to perform testing on other decommissioned equipment to provide more confidence in design safety factors.

11.0 References

11.1 Codes & International Standards

1. API RP 17B, Recommended Practice for Flexible Pipe – Fifth Edition, May 2014, Reaffirmed March 2021.
2. API RP 17L2, Recommended Practice for Flexible Pipe Ancillary Equipment – Second Edition, June 2021.
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Appendix A Definitions

A.1 Definitions

The following definitions are applied specifically to unbonded flexible pipe technology and specific sections of this report. The definitions are grouped as follows:

- Table A.1 Definitions relating to Flexible Pipe "Damage / Failure Causes"
    - The damage and failure causes which are used in the statistics shown in Section 4.0 of this report.
    - Potential failure modes for which no operational experience has been reported are shown (shaded).
    - Where possible, cross reference to the Defect References in Tables 31, 32, 33 of API Recommended Practice 17B (Ref. [1]) are included.
- Table A.2 Other Definitions

Table A.1 Definitions relating to Flexible Pipe "Damage / Failure Causes"

Damage / Failure Cause	Applicable API RP17B Defect Ref.	Description
Line Recovered Proactively - No significant damage / defect identified	n/a	Operator may elect to proactively recover a flexible pipe in order to directly establish damage / failure mechanisms (or the absence of them) through onshore inspection / dissection. Whilst this may be employed when there is a pre-existing integrity concern, it may also be used when extending the life of an asset in order to demonstrate fitness for service of the remaining lines through inspection of a line which has been subject to a more onerous operating regime.
Carcass Failure – Erosion	1.1	Carcass failure through internal erosion
Carcass Failure – Fatigue	1.5	Carcass failure through a localised fatigue mechanism. The (limited) operational experience of this mechanism relates to cases of dynamic loading in combination with excessive contact forces e.g. from a mid-water arch.
Carcass Failure - Multilayer PVDF Collapse	1.3	Carcass collapse caused by external compression from a multi-layer pressure sheath is caused by the desorption of gas from the multi-layer polymers when the bore is depressurised too rapidly, with high pressures building up between the pressure sheath layers which are resisted externally by the pressure armour, causing the carcass to collapse. The first industry failures emerged ~2001.

Damage / Failure Cause	Applicable API RP17B Defect Ref.	Description
Carcass Failure - Tearing / Pullout	Not included	Carcass tearing / pullout of the top riser end fitting occur when the carcass is overloaded along its axis. In cases where this has occurred, it is normally the result of a loss of friction / contact, exacerbated in mutli-layer pressure sheath designs, allowing the inner sheath and/ or carcass layer to pullout. This cause is also used to describe incidents in which hydrate blockage remediation leads to carcass tearing adjacent to the blockage (applicable to both flowline and riser applications).
Internal Damage - Pigging	1.1, 1.2, 2.1	Internal damage caused to the pipe by the internal transit of any pigs.
Internal Pressure Sheath – Ageing	2.1, 2.2, 2.4	Premature ageing / degradation of polymers does occur when operating conditions exceed the material limits. Most experience in this case relates to accelerated ageing of PA-11 sheaths at relatively high temperatures in combination with water.
Internal Pressure Sheath - End Fitting Pull-out	9.1	Failure is caused by inadequate crimping of the internal pressure sheath in the end fitting in combination with a relatively high coefficient of thermal expansion of PVDF pressure sheath material. Most failures occurred in the mid 1990s and the updated design approaches utilised now mitigate the risk.
Internal Pressure Sheath - Fatigue / Fracture / Microleaks	2.1	Failure of the internal sheath either due to cyclic fatigue loading, brittle fracture, or small microleaks relating to the micro-structure of the polymer.
Internal Pressure Sheath - Smooth Bore Liner Collapse	2.2	Collapse of the smooth bore liner where no internal carcass is present to support external loading. This normally occurs if the line is emptied and a vacuum is pulled in the bore. Annulus flooding does increase the external radial loading. There are also examples where external (I-tube) pressurisation caused permeation into the annulus allowing the bore to collapse / fail on shutdown, and on subsequent restart the tensile armours have catastrophically failed as they were loaded via the intermediate sheath i.e. the pressure armour is no longer supporting internal pressure.
Pressure Armour Wire Breakage - in / close to end fitting	3.1, 4.1	Pressure armour wire breakage / failure either within end fitting or close to, and related to, end effects / anchoring mechanism.

Damage / Failure Cause	Applicable API RP17B Defect Ref.	Description
Pressure Armour Wire Breakage - in main pipe section	3.1, 4.1	Pressure armour wire breakage / failure in the main pipe section, distanced from end effects / anchoring mechanism.
Tensile Armour Breakage - in / close to end fitting	5.1, 5.5	Tensile armour wire breakage / failure either within end fitting or close to, and related to, end effects / anchoring mechanism.
Tensile Armour Breakage - in main pipe section	5.1, 5.5	Tensile armour wire breakage / failure in the main pipe section, distanced from end effects / anchoring mechanism.
Tensile Armours - Birdcaging	5.2	Radial buckling of the tensile armours, typically the result of excessive compression.
Tensile Armours - Lateral Buckling	5.8	Lateral buckling of the tensile armour wires, typically the result of high radial compression in deepwater applications due to high hydrostatic pressure in combination with axial compression / reverse end-cap effects.
Corrosion of Armours - Major / Catastrophic	5.4	Armour wire corrosion is typically categorised in the *major / catastrophic* category where the effect is a failure (either *Leak* or *Rupture*) or a relatively large number of individual tensile wires have failed through the mechanism.
Corrosion of Armours - Moderate	5.4	Armour wire corrosion is typically categorised in the *moderate* category where the effect does not result in a pipe failure and the corrosion results in a relatively small number of individual tensile wire breaks (typically less than 5).
Annulus Flooding - Cause Unknown	8.1, 8.2, 9.3, 9.5,	Annulus flooding is verified by some testing / inspection means, but the source of flooding cannot be verified.
Annulus Flooding - Defective Annulus Vent System	8.1	Accidental flooding through defective vent system. This may be result of 1) vent system not being installed, 2) vent system being isolated, 3) common manifolding of vent lines from other riser annuli and failure to control flow direction (e.g. by NRV), 4) backflow from 3rd party system drains (e.g. pig trap drains) and lack of control over flow direction.
Annulus Flooding - Outer Sheath Damage - Ageing / Fracture	8.1	Degradation of the outer sheath leading to fracture. Experience has typically occurred beneath bend stiffeners / restrictors or seabed burial which provide localised insulation from the seawater / environmental cooling.

Damage / Failure Cause	Applicable API RP17B Defect Ref.	Description
Annulus Flooding - Outer Sheath Damage - Mechanical / Impact / Wear	8.1	Annulus flooding caused by sheath damage from either mechanical / impact / wear sources allowing seawater ingress to the armour annulus.
Annulus Flooding - Permeated Liquids	Not included	Low levels of liquid vapour permeation through the internal pressure sheath may occur for some designs under certain operating conditions, gradually filling the annulus with condensed liquid.
Outer Sheath Damage - Annulus NOT flooded - Ageing / Fracture	8.1	Outer sheath damage which does not result in the annulus being flooded, typically where the sheath breach is in the above-water section of flexible pipe, caused by ageing or fracture of the outer sheath.
Outer Sheath Damage - Annulus NOT flooded - Mechanical / Impact / Wear	8.1	Outer sheath damage which does not result in the annulus being flooded, typically where the sheath breach is in the above-water section of flexible pipe.
End Fitting Leak / Failure	9.2, 9.6, 9.7, 9.8, 9.9, 9.10, 9.11	Leak or failure that occurs within the pipe end fitting, or is directly caused by the proximity of the leak to the end fitting structure itself.
Ancillary Equipment - Bend Restrictor	11.1, 11.2, 11.3	Damage / degradation to a bend restrictor, including anchor / reaction collar.
Ancillary Equipment - Bend Stiffener - Connection / Interface	10.3	Damage to bend stiffener caused by the primary connection / interface mechanism.
Ancillary Equipment - Bend Stiffener - 2 part failure	10.3	Damage / degradation to bend stiffener resulting in the separation of one part of the 2-part bend stiffener, meaning the bend stiffener assembly no longer meets its design requirements.
Ancillary Equipment - Bend Stiffener – other	10.1, 10.2, 10.5	Any other bend stiffener defect not covered by the connection / interface / 2-part failure mechanisms.
Ancillary Equipment - Buoyancy Modules	12.1, 12.2, 12.3	Includes movement / loss / damage to discrete buoyancy modules.
Ancillary Equipment - CP system	17.1, 17.2, 17.3	Damage / failure specifically relating to the CP system. Note that corrosion related failures should be classified elsewhere.

Damage / Failure Cause	Applicable API RP17B Defect Ref.	Description
Ancillary Equipment - Hang-off Failure	Not included	Damage / failure of the riser hang-off system which retains the top end of a riser.
Ancillary Equipment - Hold-down Failure (tethers / clamps / connections)	15.1	Failure of a hold-down system in a tethered / buoyant wave riser configuration, normally resulting in displacement / damage to the riser system.
Ancillary Equipment - Mid Water Arch	13.1, 13.2, 13.2	Degradation to MWA. This includes tether failure, position disarrangement, loss of buoy, reduced buoyancy.
Ancillary Equipment - Vent System Anomalies / Blockage	8.1	Blockage of the annulus vent system, which may lead to annulus overpressurisation and failure of the outer sheath.
Ancillary Equipment - Other (please state which type)	n/a	Degradation of other ancillary equipment component
Global pipe defect - Dropped Object	1.3, 2.1, 3.2, 3.3, 4.2, 5.3, 7.1, 8.1	Impact from a dropped object resulting in damage / degradation to the flexible pipe.
Global pipe defect - Excess Tension	5.1, 5.5	Excess tension, typically resulting in overload / failure of the tensile armours.
Global pipe Defect - Mooring Failure / Excess Offset (see Section 4.1.2.2)	20.3	Damage / failures resulting from the catastrophic loss of mooring systems and associated excessive offsets.
Global pipe defect - Excess Torsion	3.2, 5.6, 9.7, 20.2	Excess torsion resulting in armour birdcage, excess internal compression, global pigtailing / damage / overbending.
Global pipe defect - Flow Induced Pulsation (FLIP) causing wider system effect	21.1	Damage / failure relating to FLIP, either relating to the flexible pipe or associated equipment.
Global pipe defect - Ovalisation	1.3, 3.3, 4.2	Ovalisation is typically caused by a dropped object, but may also be caused by excess contact load in high tension / contact combinations.
Global pipe defect - Overbend / Pressure Armour Unlock	3.2	Overbending past the storage bend radius and locking radius has the potential to overstrain polymer layers and unlock of the pressure armour layer (if present) leading to lack of support to the internal pressure sheath.

Damage / Failure Cause	Applicable API RP17B Defect Ref.	Description
Global pipe defect - Rough Bore Collapse	1.3, 2.3, 3.3, 20.3	Global collapse of the full pipe cross section (rough bore pipe).
Global pipe defect - Smooth Bore Collapse	1.3, 2.3, 3.3, 20.3	Global collapse of the full pipe cross section (smooth bore pipe).
Global pipe defect - Upheaval Buckling	20.1	Upheaval buckling may be caused by axial compression, particularly if the armour design is unbalanced. Inadequate installation burial depth / resistance can be a driver.
Global pipe defect - Wax Blockage	1.1, 1.2, 7.2	Excess build-up of wax in the pipe bore blocks pipe.
Global pipe defect - Excess Marine Growth	Not included	Excess marine growth can add dynamic drag loading, but heavy marine growth (up to ~3000kg/m^3) may also significantly affect the global configuration and hang-off tension.
Failure Mechanism Disputed	n/a	There is a single incident within this Sureflex JIP database where the failure mechanism was not agreed upon by the involved parties.
Other	n/a	Any other defect. In the case of this Sureflex JIP, there are no incidents recorded in this group.

Table A.2 Other Definitions

Term	Definition
Accidental	An accidental Damage or Failure case is one which is typically caused by accidental events during the flexible pipe life cycle that may not be easily mitigated in design.
Bundled Jumper	A group of jumpers which may be utilised for different services, but share common connection points e.g. production and gas lift jumpers connecting a manifold hub to a wellhead hub.
Failure Mechanism	The stages of progress from **Damage** / Failure Initiator through to ultimate **Failure**. Depending on the specific situation the timeframe for initial damage to reach ultimate failure can vary between instantaneous (e.g. impact damage) up to many years (e.g. relatively low corrosion rates leading to gradual degradation over time).
Flowline	A flexible pipe transporting gas / liquid in a single bore over considerable distance (typically >500m). Flowlines typically transport products across the seabed corridors e.g. between drill centres and platform locations. Flowlines are normally designed for static conditions.
Jumper	A flexible pipe transporting gas / liquid in a single bore over a relatively short distance (typically <500m). Subsea jumpers are used for connections e.g. wellhead to manifold, riser to pipeline. Subsea jumpers are normally designed for static (or quasi-static) conditions. Jumpers are also utilised topsides for swivels / drag-chains / connections, and are subject to some dynamic / quasi-dynamic conditions.
Riser	A flexible pipe transporting fluid in a single bore between the seabed and surface platform / floating production unit. Design for static / dynamic conditions is system specific: • For risers to / from floating production applications, dynamic conditions apply • For risers pulled through J-tubes / caissons on fixed platforms, static conditions normally apply • For risers connected to fixed platforms where the riser is subject to metocean environment, dynamic conditions normally apply
System	A system **Damage** or **Failure** case is one which occurs during the flexible pipe life cycle which may be possible to mitigate through changes to design approaches / improved industry guidance.

Appendix B Inspection & Monitoring Technology Review Tables

B.1 Inspection & Monitoring Technology Review Tables

Section 5.0 and Figure 5.1 of this report summarise a technical review of the inspection and monitoring technologies available in the industry relating to flexible pipe. The majority of the input to this assessment was in the form of structured technical presentations by vendors to the JIP steering committee, which provided feedback on use / experience of the specific technologies. In addition, JIP members have been provided with a collated reference file of all shared vendor presentations.

This Appendix includes the detailed review tables for each inspection and monitoring technology. The tables are set-out in a consistent format, including the following details:

- Technology Name
- Technology Readiness Level (TRL); 1 to 7, see Section 5.4 and Table 5.1.
- Take-Up (rating summarising the level of use in the industry); 1 to 5, see Section 5.5.
- Industry (JIP) Feedback (rating based on JIP steering committee feedback); 1 to 5, see Section 5.6.
- Summary of technology
- Benefits
- Limitations
- Procedure
- Industry Practice
- Guidance Note

Table B.1 Technology Review – Visual Inspection (ROV)

Inspection / Monitoring / Technology Name	Visual Inspection (ROV)
Technology Readiness Level (TRL) (Range 1 to 7)	7
Take-Up (Range 1 to 5)	5
Industry (JIP) Feedback (Range 1 to 5)	4
Summary	
Subsea inspections are predominantly carried out by ROVs deployed from dedicated inspection vessels. Alternatively, external visual inspections may be carried out by Divers (Table B.2), Micro ROV (Table B.3), I-tube camera (Table B.6) or Autonomous Underwater Vehicle (AUV's). However AUV's, are mostly applicable to flowlines and the technology deployment is not significantly differentiated from their application to rigid pipeline systems and the technology is not reviewed further here.	
Benefits	**Limitations**
• Identifies gross damage / leakage / failure. • Allows review of ancillary equipment condition / position, and also system CP survey. • No significant issues with regards interpretation of results.	• External visual inspection is often limited to the identification of gross defects, often once a failure mechanism has progressed. • Marine growth / seawater sediment can significantly limit visibility. • Inspection close to vessel hull / near critical connector / bend stiffeners often restricted. • Inspection within I-tubes, under bend stiffeners / connectors / clamps not possible, where the risk of outer sheath abrasion is significant.
Procedure	
In most historical cases, ROVs are deployed from specialist third party vessels. Advances in technology have allowed for the creation and utilisation of micro-ROVs which can be deployed from the same asset as the flexible pipe, refer to Table B.3 for further details. Inspection operations can be restricted by wave height, current, visibility, the presence of certain types of debris (e.g. rope and fishing nets) and operational constraints. In flexible pipe systems, General Visual Inspection (GVI) normally refers to a basic 2-pass inspection from a distance of up to 3 metres with the primary focus to identify any gross damage. Inspection which is more detailed and / or requires additional specialist equipment is normally referred to as Close Visual Inspection (CVI).	
Industry Practice	
ROVs are the most commonly adopted technique within the industry for subsea visual inspections. The visual	

examination considers the general layout and configuration of the flexible pipe system, which includes all ancillary equipment. The inspection frequency is normally based on a risk assessment, with more critical components having increased inspection, although there are significant regional variations. Conversely, some operators have used the results of other inspection techniques to extend and/or stagger their GVI intervals. As part of the General Visual Inspection (GVI) technique, a base-line survey is usually undertaken of the general layout and configuration following installation and commissioning. The GVI programme determines the physical location and condition of all flexible pipe components and ancillary equipment. In-service inspection should also consider the extent of soft or hard marine growth and the need for riser cleaning (refer to Table B.8 for further information). However, the riser cleaning operation is not widely performed on a regular basis; anecdotal evidence indicates that soft marine growth may not establish itself sufficiently on flexible pipe to survive seasonal storms. There have been a limited number of incidents in which high density marine growth deposits have adversely affected riser configuration and have required intervention (cleaning programs) to restore the riser system.
Guidance Note
Visual examination is recommended after installation and commissioning to detect damage and gross deviations from the design basis. The GVI technique is limited to detection of gross damage and bore fluid seepage. It is unlikely that GVI will detect a small outer sheath defect and potential annulus flooding, especially in the case where the pipe is subject to marine growth or staining. However, it is not uncommon for GVI to detect outer sheath breaches where permeation rates are significant. The GVI frequency should be risk based in line with the integrity strategy. Additional inspections outwith this frequency may be required where specific knowledge indicates it would be beneficial (e.g. following a dropped object incident). A GVI of the bend stiffener / floating facility interface locations may be challenging or restricted due to poor access between dynamic risers or as a result of environmental conditions. This means detailed inspection by ROV requires prioritisation in suitable weather windows, or alternative inspection approaches. As alluded to above, bubbles in the vicinity of flexible pipes may indicate permeated gas exiting through an external sheath breach. However, bubbles emanating from close to flexible pipe end-fittings are not necessarily anomalous (as have been reported in the past) and could be intentional venting of permeated gas through GRV's. Following inspection, the locations and depths of any key features (buoyancy modules, anomalies etc.) should be recorded for future review and assessment. This should be retained and updated for the life of the flexible and shared with the inspection party prior to performing ROV surveys.

Table B.2 Technology Review – Visual Inspection (Diver)

Inspection / Monitoring / Technology Name	Visual Inspection (Diver)
Technology Readiness Level (TRL) (Range 1 to 7)	7
Take-Up (Range 1 to 5)	2
Industry (JIP) Feedback (Range 1 to 5)	4
Summary	
This technology review is "by exception / difference" to the related "Visual Inspection (ROV)" from Table B.1.	
Benefits	**Limitations**
• Allows close access to the most critical locations around hang-off / bend stiffeners (subject to environmental limitations and vessel design). • Generally allows for more detailed inspections to be completed when compared to ROV based inspection.	• HSE risks to dive personnel. • Limited by maximum attainable depths. • Requires dive spread on the asset or a dive support vessel.
Procedure	
Divers require the support of dedicated specialised equipment and/or support vessels in order to operate and complete inspections.	
Industry Practice	
The use of divers to undertake visual inspection is uncommon and limited to shallow water depths. Furthermore, the health and safety risks associated with diving at any depth means that there is a shift by operators from employing this method for visual inspection where alternatives exist.	
Guidance Note	
Due to the health and safety risks that are associated with diving, the routine use of diver based visual inspection is infrequent. The key benefits of divers being able to access areas that historically ROVs could not (between risers, close proximity to vessels, shallow waters) has been somewhat removed by the availability of an increasing number of Micro-ROVs, see Table B.3 for further details. There will, however, remain cases where the most appropriate inspection method is to utilise divers.	

Table B.3 Technology Review – Visual Inspection (Micro-ROV)

Inspection / Monitoring / Technology Name	Visual Inspection (Micro-ROV)
Technology Readiness Level (TRL) (Range 1 to 7)	7
Take-Up (Range 1 to 5)	2
Industry (JIP) Feedback (Range 1 to 5)	4
Summary	
This technology review is "by exception / difference" to the related "Visual Inspection (ROV)" from Table B.1 and relates to the deployment of small lightweight ROVs that can typically be deployed by 1-2 people with limited infrastructure requirements.	
Benefits	**Limitations**
• Large reduction in cost compared to ROV / Diver inspection as no 3rd party vessel or platform spread required. • Can allow more regular access to some of the most critical locations around hang-off / bend stiffeners.	• Current power / depth limits (or perception of limits) normally restrict inspections to upper riser sections of the system. • Same visual limitations as listed in Table B.1.
Procedure	
In this case, a small ROV (often being within single person manual handling limits) is deployed directly from the asset associated with the riser. In the case of an FPSO, this may be deployed over the side of the hull, through the turret / moonpool, or through a spare I / J-tube, allowing access close to the riser hang-offs.	
Industry Practice	
Several operators have reported that they have experience of utilising micro-ROVs to complete inspections that would historically have been completed by divers or suffered from restricted inspections due to access limitations of conventional ROVs.	
Guidance Note	
Deployment of micro-ROVs may be considered where more frequent risk-based inspections are required around the riser connections / bend stiffeners close to the water surface.	

Table B.4 Technology Review – Visual Inspection (Rope Access Technician)

Inspection / Monitoring / Technology Name	Visual Inspection (Rope Access Technician)
Technology Readiness Level (TRL) (Range 1 to 7)	7
Take-Up (Range 1 to 5)	2
Industry (JIP) Feedback (Range 1 to 5)	4
Summary	
This technology review is "by exception / difference" to the related "Visual Inspection (ROV)" from Table B.1. Completion of GVI and CVI of the riser air zone including the bend stiffener and bend stiffener connections to the asset where these are located above sea level and exposed to the environment i.e. not in J/I-tubes.	
Benefits	**Limitations**
• Confirms external condition of the bend stiffener and critical connections. • Readily allows gross damage or deformity of the riser to be identified.	• Ability to inspect within the splash zone may be restricted by environmental conditions. • HSE risks to rope access personnel / over-side working. • Normally requires standby vessel to be on location as part of risk mitigation. • May require additional scaffolding to be built to facilitate rope access work.
Procedure	
Rope access team deployed from the asset to complete visual inspection of the riser and ancillary equipment within the accessible air zone.	
Industry Practice	
Standard over-side rope access working requirements applied, normally requiring standby vessel on site and / or fast rescue craft deployed (or sea state within fast rescue craft launch limits).	
Guidance Note	
As an alternative to rope access, inspection of air zone equipment may be completed directly from the asset itself or from support vessels where access is practicable using binoculars or digital magnification as necessary. Where the requirement for close inspection exists, or access restrictions prevent remote visual inspection of the area of interest then the applicability of rope access inspection, or the use of Remotely Operated Aerial Vehicles (ROAV's) Table B.5 should be considered.	

Table B.5 Technology Review – Visual Inspection – Remotely Operated Aerial Vehicles (ROAV's)

Inspection / Monitoring / Technology Name	Visual Inspection – ROAV
Technology Readiness Level (TRL) (Range 1 to 7)	7
Take-Up (Range 1 to 5)	1
Industry (JIP) Feedback (Range 1 to 5)	4
Summary	
This technology review is "by exception / difference" to the related "Visual Inspection (Rope access Technician)" from . Completion of GVI and CVI of the riser air zone and ancillary equipment utilising a Remotely Operated Aerial Vehicle (ROAV).	
Benefits	**Limitations**
• Likely reduction in cost compared to Rope Access Technician inspection as reduced number of personnel and no standby vessel is required. • Through comparative cost reduction, can allow more regular access to the most critical locations around air zone hang-off / bend stiffeners. • Can review large areas and move on to alternate locations faster than a rope access team.	• Operation limited by environmental conditions (e.g. wind speed). • Perceived or actual threats of impact and / or loss of the vehicle. • Inspection time limited by battery life (routinely mitigated by returning the ROAV to the asset to replace the battery pack). • Use restricted during helicopter operations.
Procedure	
The ROAV (routinely smaller than 1 meter across) is readily deployable direct from the asset and much like a subsea ROV is controlled by a pilot who monitors the ROAV position either directly or via a video display linked to the ROAV's on board camera(s).	
Industry Practice	
ROAV deployment onshore to complete surveys of tall structures or areas where the risk of injury to personnel precludes manned inspections has become increasingly more commonplace. The technology has further been developed to allow for additional inspection techniques to be deployed from the ROAV (e.g. UT inspection). Several operators have utilised ROAV packages to complete online inspection of flare stacks along with deployments of ROAVs to inspect in air zone risers down to the waterline, where previous inspections relied on roped access. The routine application of ROAVs for the inspection of flexibles is uncommon and is typically only utilised based on specific concerns over damage or anticipated issues with ancillary equipment.	

Guidance Note
Where access allows and the specific requirement exists, ROAVs present a viable alternative to more traditional methods.

Table B.6 Technology Review – I-tube Inspection

Inspection / Monitoring / Technology Name	I-tube Inspection
Technology Readiness Level (TRL) (Range 1 to 7)	7
Take-Up (Range 1 to 5)	2
Industry (JIP) Feedback (Range 1 to 5)	4
Summary	
Where access allows (or is created retrospectively) between the riser outer sheath and the inner surface of the I-tube, visual inspection of the riser outer sheath for gross defects may be performed (both above and below the waterline). With some system designs, inspection of bend stiffener retaining mechanisms / wires is also achievable.	
Benefits	**Limitations**
• Allows visual inspection of riser outer sheath through the splash zone area within the I-tube. • Identifies gross damage of the outer layer(s), and can identify requirements for follow-up inspection on critical areas.	• Locations of potential outer sheath breaches resulting from contact / abrasion are unlikely to be visible due to contact. • Requires access to the I-tube, which can be challenging if not considered at the design stage.
Procedure	
Where access is available “by design” a camera system is normally deployed into the annular space around the riser from above. The camera inspection tool is then lowered within the I-tube allowing inspection around the circumference over the accessible length within the I-tube. In some cases, access has been retrospectively created by cutting / milling into I-tubes.	
Industry Practice	
The inspection technology has a relatively low take-up as a preventative inspection requirement. However, in cases where an annulus breach / outer sheath breach is identified within the splash zone area, inspection may become a key assurance activity due to the risk of corrosion. There have been cases where risers have been shut-down due to integrity concerns relating to such cases where inspection has not been possible. In other cases where I-tube inspections have been successfully deployed, a number of features have been visible, as follows: • Degradation of bend stiffener retention wires, prompting remedial change-outs, • Bursts of the riser outer sheath, both close to the waterline and above, • Ballooning of outer sheaths within I-tubes to a point where the space between the outer sheath / I-tube wall is effectively blocked,	

- Installation damage to outer sheaths,
- Verification of sheath breach through bubbles from the outer sheath locations at contact points,
- Post-failure inspection within I-tubes visually confirming the location of catastrophic failures.

Guidance Note
As noted in Sections 6.6.1 and 6.6.2, it is recommended that major accident hazard threats / mitigations are identified and that accessibility for in-service inspection is considered at an early design stage. In many existing FPSOs / platforms, the accessibility into the I-tubes normally requires extensive invasive intervention. These locations on a riser often represent some of the highest risk locations due to the high consequence of failure and the threat of general corrosion relating to splash-zone breaches. As noted in Table 4.18 these cases have led directly to catastrophic pipe ruptures in the past, as well as further cases of damage. It is recommended in future developments that consideration is given to the inspection access requirements at an early design stage. It is considered likely that the industry take-up of this inspection approach may correspondingly increase in the future.

Table B.7 Technology Review– LASER Measurement / Photogrammetry

Inspection / Monitoring / Technology Name	LASER Measurement / Photogrammetry
Technology Readiness Level (TRL) (Range 1 to 7)	7
Take-Up (Range 1 to 5)	2
Industry (JIP) Feedback (Range 1 to 5)	5
Summary	
The use of laser measurement systems to inspect components / infrastructure and produce models that are capable of extremely high degrees of accuracy.	
Benefits	**Limitations**
• Produces detailed accurate models of what has been inspected. • Confirms as built / as found condition of components. • Non-intrusive visual inspection technique. • Suitable for use topsides (e.g. internal carcass measurement) and subsea (external). • Can be deployed in many configurations including diver, ROV, crawler and permanently mounted to a structure. • 3D model transferrable for subsequent analysis.	• Marine growth / seawater sediment can significantly limit visual inspection. • Inspection close to vessel hull / near critical connector / bend stiffeners often restricted. • Inspection within I-tubes, under bend stiffeners / connectors / clamps not possible, where the risk of outer sheath abrasion is most significant. • Only details the visible surfaces inspected (although this can allow for internal condition to be inferred).
Procedure	
All of the inspection tools produced by the different vendors operate on a similar principal. The tool projects a laser onto the surface of the equipment being inspected and uses time of flight responses to identify the distance to the surface. Many of the tools are capable of recording individual distances between the tool and equipment at rates in excess of 500 records per second. These individual records are subsequently collated using computer software to produce a 3D image of the inspected equipment. This model can be used as a one off to permit further analysis or a series of models can be produced and compared to identify changes in the orientation of the equipment over time.	
Industry Practice	
Whilst GVI and CVI inspection using video is commonplace within industry the use of LASER measurement scanning is predominantly restricted to situations where highly detailed measurements are required. LASER measurement techniques have been used by several operators to aid with defect assessment and anomaly identification but are not routinely deployed.	

Guidance Note
The accuracy obtained by the inspection tool is frequently linked to the distance of the tool from the equipment being inspected. Whilst accuracies within microns can be obtained this normally requires a standoff distance of significantly less than 2m between the inspection tool and the equipment being inspected. Where such a high tolerance is not required the standoff distance can be increased, with some vendors reporting inspection capabilities with a standoff of 10m and more.

Table B.8 Technology Review – Marine Growth Removal

Inspection / Monitoring / Technology Name	Marine Growth Removal
Technology Readiness Level (TRL) (Range 1 to 7)	6[1]
Take-Up (Range 1 to 5)	3
Industry (JIP) Feedback (Range 1 to 5)	4
Summary	
In addition to using divers, multiple tools at varying degrees of complexity and maturity have been developed to assist with marine growth removal on flexible pipes and ancillary equipment (typically riser applications). The tools may be attached to the risers in the air zone by rope access teams, attached subsea by an ROV, or manipulated directly via ROV control.	
Benefits	**Limitations**
• Removes marine growth to allow clear access for inspection / repair activities. • Removal of dense marine growths reduces additional weight, returning it to the as designed condition.	• Not all solutions are capable of removing ropes or fishing debris. • Potential for damaging the flexible pipe outer sheath / ancillary equipment during cleaning operations. • Access can be challenging, particularly around interfaces with ancillary equipment. • Riser specific solutions may not be capable of cleaning ancillary equipment. • Potential for tooling to become snagged on marine debris such as nets / ropes.
Procedure	
The need to complete marine growth removal is normally identified as either a precursor to or result of inspection activities. Cleaning tools vary considerably from ROV mounted scrapers to riser mountable solutions designed specifically for the task which can be mounted within the air zone or subsea. The riser specific cleaning solutions include designs based around different techniques including jetting systems using pressurised water and rotating mechanical cleaners of different designs such as nylon brushes and rubber fins. Some of the riser mountable solutions include combinations of these technologies and also camera systems to confirm cleaning progress / complete close inspection.	
Industry Practice	
Many operators have identified the need to remove marine growth from their flexible pipes for numerous reasons	

including, but not limited to: allowing visual inspection to take place; removing heavy coral deposits that were affecting riser buoyancy and to allow riser repairs to take place; to allow the installation of new equipment. The operational environment, specifically water depth, and the length of flexible requiring cleaning have been seen to impact which solution is selected by operators. Diver based solutions are more frequently utilised in shallow waters or in the immediate vicinity of the asset, whilst ROV mountable or bespoke cleaning equipment may be utilised when larger lengths of riser or areas at depth, require attention. Industry feedback, although generally positive, varies depending on the method and equipment used, with each of the methods having their own advantages and disadvantages. Historically, one operator is known to have used divers and domestic pressure washers with extension hoses to remove marine growth within the splashzone (see Guidance below for lessons shared with JIP membership).
Guidance Note
Water depth, length of pipe to be cleaned, the type of marine growth, along with the presence of any ancillary equipment all need to be understood to select the correct tool or method of cleaning. Historically, cleaning has typically been conducted to facilitate general visual inspection or to confirm damage. The need to complete cleaning campaigns over the full riser length is limited to a small number of cases where excessive heavy marine corals have been found to be changing the buoyancy of the risers. Whilst removal of marine growth to confirm the condition of ancillary equipment is common practice across industry, consideration should be given to the value obtained from cleaning the outer sheath of soft marine growth to facilitate visual inspections when alternative inspection techniques such as Annulus Testing (Table B.21) can be used to confirm the condition of the outer sheath. Care should be taken when utilising high pressure water jetting to ensure that damage is not caused to the riser outer sheath or ancillary equipment. Multiple operators have reported notching or gouging of subsea bend stiffeners where high pressure jetting has been utilised to remove marine deposits.

Notes 1. There are several vendors offering different services at different levels of complexity, maturity and readiness varying between concept & TRL 7.

Table B.9 Technology Review – Environment Monitoring

Inspection / Monitoring / Technology Name	Environment Monitoring
Technology Readiness Level (TRL) (Range 1 to 7)	7
Take-Up (Range 1 to 5)	4
Industry (JIP) Feedback (Range 1 to 5)	4
Summary	
Sensors fitted to the asset, support vessels or purpose-built buoys collect information on the environmental conditions such as barometric pressure, wind speed and direction, the sea and air temperature and key information pertaining to the flexible riser system such as the wave height, wave period and spectral response. The data is collated and used to forecast future events and also retrospectively to analyse loading of the risers. Knowledge of the actual environmental conditions witnessed during operation allows for a comparison to be made against the design criteria and forms an input to fatigue loading calculations.	
Benefits	**Limitations**
• Internationally recognised method. • Regular updates on conditions available. • Supports design verification / life extension activities.	• Local conditions may not be monitored, may rely on inference from nearby monitoring systems.
Procedure	
Environmental data is collected using different methodologies dependant on what information is pertinent to the asset. The collected data is used to support multiple activities relating to the asset as a whole; as such not all obtained information may be pertinent to assessments for flexible pipes and a degree of data filtering will be required prior to use. Collection methods vary from passive assessments (a physical observation of the external conditions recorded by an offshore operator) to sophisticated active monitoring systems. Active monitoring systems vary, but typically data is collected from either a moored monitoring buoy, from sensors located on the asset itself or from representative nearby assets. The environmental information is collected on a near continuous basis, allowing for real time assessments to be completed and the ability to produce historical trends or re-baseline design conditions.	
Industry Practice	
Almost all operators monitor the environmental conditions to some degree, either directly from their own asset, using information from proximal assets or by supporting the continued operation of weather monitoring buoys. The extent to which the information is used varies considerably. The environmental information can be used as an input at the design stage, for monitoring during service life and at the end of life to assist with life extension works where the information can provide an insight into the fatigue loading witnessed by the riser.	

Guidance Note
Whilst the information can be used at all stages in the life cycle of a flexible, care must be taken to ensure that the information used is representative of conditions at the asset location. This is most pertinent where information from adjacent assets or weather buoys located some distance from the asset is used. Localised wave height amplification has been witnessed around FPSOs where waves that have rebounded from the vessel combine with incoming waves. This additive effect has resulted in significantly larger wave heights being witnessed at some locations in the immediate vicinity of vessels whilst conditions elsewhere were relatively benign.

Table B.10 Technology Review – Offset and Motion Monitoring

Inspection / Monitoring / Technology Name	Offset and Motion Monitoring
Technology Readiness Level (TRL) (Range 1 to 7)	7
Take-Up (Range 1 to 5)	5 (offset) 4 (motion monitoring)
Industry (JIP) Feedback (Range 1 to 5)	4
Summary	
Where a production asset is not rigidly fixed to the seabed but has a degree of free motion, then sensors (typically GPS receivers) are attached to the asset to monitor its position and record any instances where it moves outside of its designed operational envelope. Accelerometers, gyroscopes or strain sensors can also be fitted to the asset or risers to provide a record of experienced motions which may be compared against vessel RAOs utilised in the design phase and are specifically of benefit during analysis of failures or during life extension assessments.	
Benefits	**Limitations**
• Validates actual operation against the conditions considered during design. • Offset monitoring can identify mooring chain or riser failure by identifying vessel movement significantly outside of the normal operational envelope.	• Not all motions are readily measurable using single sensor GPS types.
Procedure	
Where the design of an asset dictates that the position/motion is not fully constrained, it is necessary to identify how the offset/motions will affect the design life of the attached flexible pipes. The position of the asset can be monitoring using a single GPS receiver however, where vessel motions (pitch, roll, yaw etc.) are also required then additional sensors such as further GPS receivers, accelerometer, or gyroscope based systems may need to be installed at different locations around the asset to monitor the host facility movements. The data provided by the sensors can be presented graphically in the control room to indicate when the asset is operating outwith its designed limits or can be stored for analysis at a later date.	
Industry Practice	
GPS sensors are widely used across the industry to confirm the positional location of floating host facilities. Movement sensors are less common but may be installed where specific environmental conditions or vessel characteristics are deemed to present an integrity risk. At least one operator is known to have utilised data provided by offset and motion monitoring sensors to justify riser	

life extension by demonstrating that the operational conditions were consistent with design assumptions.
Guidance Note
Offset / excursion monitoring is routine around the globe for floating production systems. Motion monitoring systems should be considered as a means to validate vessel / riser motions against analytical approaches.

Table B.11 Technology Review – Embedded Curvature Monitoring

Inspection / Monitoring / Technology Name	Embedded Curvature Monitoring
Technology Readiness Level (TRL) (Range 1 to 7)	5
Take-Up (Range 1 to 5)	1
Industry (JIP) Feedback (Range 1 to 5)	N/A
Summary	
A series of sensors are embedded in a dedicated polyurethane layer underneath the polymer outer sheath during the fabrication process. The signals from the sensors can be analysed to provide the torsion, temperature and shape of the riser in the area of the sensors. The combined sensor data is then used to produce a 3D curvature model of the riser within the area covered by the sensors, typically around the bend stiffener.	
Benefits	**Limitations**
• Does not impact on the core structure of the flexible, allows for standard design and material to be used. • Should allow design verification (extreme and fatigue cases).	• Not a retrofit solution. • The response of a single monitored riser may not be representative of all risers within the system as the additional layer of embedded sensors may affect the bend stiffness and response of the pipe. As such additional calculation/analysis may be required in order to infer the condition of unmonitored adjacent risers.
Procedure	
When specified at the design stage, the sensors are installed into a purpose built layer in the flexible extending through the bend stiffener area. The curvature, torsion and temperature data is collected and sent to a central control station where the results are displayed and stored for future analysis. The monitoring system is equipped with alarms to indicate if the flexible is operating outwith its design parameters. It is planned to subsequently develop a system that will take the cyclic loading information obtained by the sensors and use this as an input to a fatigue assessment tool to automatically account and present the accumulated fatigue damage that the riser has been subjected to. The cycle counting of in-situ curvature ranges should also allow for comparison against the design fatigue analysis in order to re-benchmark the fatigue life of the flexible.	
Industry Practice	
A number of historical retrofit curvature monitoring systems developed over the last 20 years have suffered from operational issues relating to calibration, sensor failure, and control line failures. One of the currently proposed systems by a manufacturer aims to mitigate these previous weaknesses by embedding sensors in a specific layer during manufacture. Assessment of accumulated fatigue damage has been used widely across the industry to	

provide justification for the life extension of flexible pipes. This has historically taken the form of FEA modelling, comparing the designed load case and model with an assessment of the actual loading conditions. The proposed system considered here would provide higher clarity information to these assessments such that conservatisms can be removed, potentially providing more confidence in the continued operation of the flexible beyond its design life or confirming that the riser should be removed from service.
Guidance Note
Full scale prototypes of the system have been developed and successfully provided representative curvature information during onshore testing. The final prototype tests were completed in 2016, and the technology deemed qualified by the vendor. However, to date the vendor notes that there have been no operational deployments. As with all embedded systems, the efficacy of the system relies on the system operating reliably throughout the life of the flexible pipe. For a 3 m bend stiffener, typically in the region of 45 sensors would be installed, of which as few as 12 are required to reliably produce results. The system has also been designed with a 50% redundancy in the cabling system so as to minimise impacts of accidental damage.

Table B.12 Technology Review – Sonar Monitoring

Inspection / Monitoring / Technology Name	Sonar Monitoring
Technology Readiness Level (TRL) (Range 1 to 7)	6
Take-Up (Range 1 to 5)	1
Industry (JIP) Feedback (Range 1 to 5)	4
Summary	
A single or multi beam based sonar technology designed to monitor in real time, the presence and position of risers and mooring lines in the proximity of the riser hang-off area.	
Benefits	**Limitations**
• No mechanical moving parts or batteries. • Designed for life of field. • Designed to be installed from FPSO. Reduces diver or ROV intervention (initial deployments were retrofit through spare I-tubes).	• Requires line of sight to target. • May require multiple sonar heads for congested turrets. • May require periodic retrieval / cleaning to remove marine growth from sonar head.
Procedure	
The sonar monitoring system is deployed on a rigidly located tool and lowered through a spare slot in the turret (or a dedicated deployment slot in the case of new build vessels) and extended below the level of the bend stiffeners. The transceiver emits a horizontal sonar beam through 360°, when the beam impacts a solid object it is reflected back to the transceiver and the timing between transmission and reception is used to generate and record sonar images of the spatial positions of the risers (and moorings). Where multiple transceiver heads are utilised the timing of sonar "pings" is offset to ensure interference between each of the sensors does not occur.	
Industry Practice	
One operator is known to have installed sonar monitoring systems, including single and multiple sensor installations. These have successfully identified the loss of a bend stiffener by highlighting riser motions that were significantly outside the expected normal ranges.	
Guidance Note	
As sonar systems operate based on the reflection of sound waves, line of sight between the transceiver head and the risers, and angular separation of the target is a critical requirement. Although to date sonar monitoring systems have only been installed in turret moored vessels, there is no reason why the system could not be installed on any asset to monitor flexible riser movement. Debris within the riser hang-off area will also be detected by the sonar system however, dependant on the location of the debris, it may impact on the operation of the system.	

Table B.13 Technology Review – Integrated Fibre Optic Monitoring - Strain

Inspection / Monitoring / Technology Name	Integrated Fibre Optic Monitoring - Strain
Technology Readiness Level (TRL) (Range 1 to 7)	6
Take-Up (Range 1 to 5)	2
Industry (JIP) Feedback (Range 1 to 5)	2
Summary	
Embedded / integrated optical fibres with Fiber Bragg Gratings are used for direct measurement of the strain in the tensile armour wires of flexible pipe. Sensors are placed in areas of highest loading i.e. under bend stiffeners and at hang-offs inside I-tubes.	
Benefits	**Limitations**
• Ability to monitor strain in areas of highest loading. • May detect tensile armour wire breakage. • Enables validation of design methodology.	• Cannot be retrofitted.
Procedure	
The procedure involves integrating sensors into the flexible pipe structure during manufacture which make it possible to monitor the dynamic response of the flexible pipe in real time and obtain a detailed knowledge of fatigue and extreme wire stresses experienced by the flexible pipe. This is achieved using a method of Fibre Bragg Grating (FBG) which makes it possible to measure small shifts in the optical pattern within the optical fibre. When a strain is applied to the flexible pipes armour wires, the interference pattern shifts, thus allowing the strain to be measured.	
Industry Practice	
Although strain measuring has been available as an option for some years, there are a limited number of in-service flexible pipes with fibre optic monitoring integrated into the armour wires. One operator provided feedback that the system has proved challenging to capture useful/useable information.	
Guidance Note	
All manufacturers of flexible pipe offer fibre optic monitoring to varying degrees, however, the CAPEX involved has, to date, resulted in limited industry up-take. Consideration should be given to fibre optic strain monitoring of risers where the operational and / or environmental conditions are close to the current limits of flexible pipe technology. In particular, the purchase of one instrumented riser can provide comparative information for the entire riser system. A factor in considering this monitoring technology is the topsides interface in terms of restricted areas, power supply, data transfer / logging and maintenance requirements, as these will require to be accounted for at the design stage.	

Table B.14 Technology Review – Retrofit Bending Control

Inspection / Monitoring / Technology Name	Retrofit Bending Control
Technology Readiness Level (TRL) (Range 1 to 7)	6 (split bend stiffener) 5 (partially stiffened restrictor)
Take-Up (Range 1 to 5)	1
Industry (JIP) Feedback (Range 1 to 5)	N/A
Summary	
Installation of retro fit bending control equipment to replace damaged or failed bend stiffeners without recovering and re-terminating the riser.	
Benefits	**Limitations**
• Allows bending control to be re-established on systems where original equipment has been damaged or failed. • Can be used as a means to extend service life of risers with damaged/failed bend stiffeners.	• Solutions typically do not have identical properties as the original design specification equipment. • Solutions may not be compliant with API 17L [5] depending on solution selected. • Limited riser experience (experience to date focussed on cable/umbilical risers).
Procedure	
Following damage or loss of the original equipment bend stiffener the retrofit solution is installed without the removal and re-termination of the flexible. Design solutions vary but typically involve the removal of the original equipment (where still present) and subsequent installation of a split bend stiffener or a collection of bend restrictor elements with variable bending control properties.	
Industry Practice	
Whilst there are several examples of retrofit bending solutions being installed on non-hydrocarbon carrying flexible and umbilical risers the experience of installing retrofit solutions for hydrocarbon systems in dynamic operations is very limited.	
Guidance Note	
With any known damage or failure of bending control it is essential to assess the extent of any accelerated fatigue related damage that may have accrued prior to remediation to determine if the pipe remains safe for continued operation. This should include an assessment of the likelihood of there being failed tensile armour wires or unlocking of pressure armours as a result of localised overbending.	

As retrofit solutions typically do not have the exact same properties as the originally designed equipment, assessment of the remaining fatigue life of the flexible should be undertaken to identify the remaining useful life of the replacement system. Several operators have investigated combining a retrofit system with raising the riser hang-off to move the fatigue hot spot away from the area of bending as a means of further extending riser life to allow for replacement risers to be procured. Retrofit bend stiffeners are therefore most commonly seen as a short to medium term temporary repair solution rather than a long-term permanent replacement.

Table B.15 Technology Review – Temperature Monitoring – Inline

Inspection / Monitoring / Technology Name	Temperature Monitoring – Inline
Technology Readiness Level (TRL) (Range 1 to 7)	7
Take-Up (Range 1 to 5)	5
Industry (JIP) Feedback (Range 1 to 5)	4
Summary	
Basic measure to monitor bore temperature.	
Benefits	**Limitations**
• Allows the risk of thermal degradation of the polymer liners to be defined in most cases • Allows the risk of pressure sheath creep through temperature (and pressure) cycling to be monitored • Allows for more refined internal corrosion and flow assurance assessments to be completed.	• Traditional technology limits the placement of temperature transducers at multiple places along a subsea system meaning the flexible pipe entry (or exit) temperature may not be known e.g. monitoring limited to turret / FPSO location on a production (import) riser. • Assessments typically rely on the availability of additional inspection/monitoring data (e.g. water content, CO_2 concentration, pH etc.) in order to complete assessment. • Some temperature sensor fittings can be subject to vibration risks due to FLIP. • Subsea sensors are vulnerable to degradation in later life with limited opportunity for rectification.
Procedure	
Monitoring of the bore temperature is predominantly performed using standardised sensors located in the topsides facilities and/or from locations upstream of the flexible pipeline, i.e. templates, wells or manifolds. Distributed temperature sensors can be installed at the manufacturing stage to measure temperature along the length of a flexible. Retro fit external sensors, attached to rigid pipework upstream of the flexible, have been utilised to provide indicative (±1°C - 2°C) temperatures where the upstream sensors have failed or previously not been installed (Refer to Table B.16 for further details).	
Industry Practice	
In many historical cases, monitoring was limited to topside equipment which made assessment of individual production jumpers difficult to perform due to the comingling of production fluids from several wells into a common	

header. Many operators have identified the benefit of logging well-head temperatures to give more representative information, however this "worst case temperature" can lead to conservative assessments where fluids cool prior to entering the flexible. Many operators utilise data loggers to continuously record temperature information such that it can be interrogated at a later date for life extension studies or integrity reviews. Guidance is provided in Ref. [16] for a minimum sampling rate of a 1-hourly mean temperature, though recommends actual intervals and frequencies are based on a specific risk assessment. A 1-hourly sampling rate is likely to be excessive for lower risk pipes. Several operators interrogate minimum, mean and maximum temperatures at differing frequency, which has proven to be beneficial when completing specific assessments. The ability to retrospectively interrogate data at different frequencies requires logging of the full history with a high sampling rate. The sampling rate and monitoring / review frequency should be risk based, and reviewed once a baseline has been established.
Guidance Note
The bore temperature is a basic monitoring requirement. It is recommended that continuous monitoring and, as a minimum, daily logging (typically min, mean, max) of the temperature should be performed. The magnitude of the bore temperature is important to establish the degree of ageing for polyamides and tape layers. The temperature cycle range is important for establishing degradation in PVDF pressure sheaths. The most conservative data will typically come from the hottest location of the flexible pipe system. This invariably requires a temperature monitoring facility near the wellhead for subsea production systems. Monitoring of extreme low temperature at these locations is important during start-up operations to identify risk of polymer sheath embrittlement. Extrapolation of monitoring data from locations remote from the high temperature source requires a degree of caution, and a tolerance should be applied to the predictions to gauge the sensitivity in the polymer degradation result. This extrapolation of data can be affected by different flow conditions, or co-mingling of produced fluids in a subsea manifold and may require flow assurance calculations to predict pipe temperature from sensors some distance from the location of interest. In-line coupon monitoring systems (Ref Table B.29) should be considered where predicted operating temperatures are close to the design limit. A level of heat energy from the bore fluid normally dissipates through the flexible pipe layers to the outer sheath and local environment (sea or air). Where the outer sheath is insulated e.g. through: burial, installation of ancillary equipment (buoyancy modules, clamps, bend stiffeners, PFP etc.) or where stagnant conditions exist (such as within I-tubes or caissons with limited fluid replenishment), this can lead to a localised temperature build up. There is experience of long-term exposure to elevated temperatures, e.g. beneath the bend stiffener, causing hydrolysis and brittle failure of the polymer outer sheath, as such this effect should be considered in the thermal design of the pipe.

Table B.16 Technology Review – Temperature Monitoring – Remote (external sensor)

Inspection / Monitoring / Technology Name	Temperature Monitoring – Remote (external sensor)
Technology Readiness Level (TRL) (Range 1 to 7)	6 (ROV transfer), 5 (Wireless transfer)
Take-Up (Range 1 to 5)	2
Industry (JIP) Feedback (Range 1 to 5)	4
Summary	
This technology review is "by exception / difference to the related "Temperature Monitoring – Inline" (Ref.Table B.15). This section considers the use of external retrofit sensors attached to rigid pipework in the vicinity of the flexible pipe to monitor bore temperature.	
Benefits	**Limitations**
• Can be retro fitted to pipes where inline sensors have failed / not been installed. • Options for ROV contactless data retrieval or wireless data transfer for real-time online monitoring.	• Offline systems (ROV recovered data), only permits retrospective analysis and can be costly to recover data. • Data transferred using wireless technology may be subject to interference depending on range, environmental conditions and transfer method employed (e.g. acoustic, radio frequency, free space optical etc.), although there is no specific experience of this in this application.
Procedure	
Retrofit external sensors are installed onto rigid pipework upstream of the flexible by diver or ROV. Data may be stored and recovered via contactless data transfer to ROV or wireless transmission of the data to a topsides processing centre.	
Industry Practice	
Limited application of the technology was reported in the period 2010 - 2015, to provide indicative temperatures within the bore of the flexible where subsea temperature transmitters had failed. Indications are that the technology provides temperatures with an accuracy to within ±1°C - 2°C of the actual fluid temperature.	
Guidance Note	
Limited to historic applications.	

Table B.17 Technology Review – Integrated Fibre Optic Monitoring - Temperature

Inspection / Monitoring / Technology Name	Integrated Fibre Optic Monitoring - Temperature
Technology Readiness Level (TRL) (Range 1 to 7)	7
Take-Up (Range 1 to 5)	2
Industry (JIP) Feedback (Range 1 to 5)	4
Summary	
Embedded / integrated fibre optics are used for direct monitoring of the temperature profile over the length of a flexible pipe, which can be used to determine if there is a risk of thermal degradation to the polymer layers and / or if flooding of the annulus has occurred.	
Benefits	**Limitations**
• Able to monitor temperature along length of flexible including at critical areas e.g. under bend stiffener. • Detects outer sheath breaches, based on temperature change. • Verifies location of ancillary components based on temperature profile differential over pipe length • Data may support other hydrate management / flow assurance assessments..	• Cannot normally be retrofitted, unless planned for in design (either directly inserting, or including a conduit for subsequent fibre optic installation). • Flooding detection requires a temperature gradient between the bore and external ambient seawater.
Procedure	
The procedure involves integrating sensors into the flexible pipe structure during manufacture which make it possible to monitor temperature across the riser length in real time. This is achieved using a method of Raman or Brillouin scattering, which makes it possible to measure the temperature at any given point along the length of the fibre. Some systems offer continuous monitoring allowing the time and location of damage to be inferred through the temperature change, whilst others only allow discrete inspection / testing. Systems can also infer the location of ancillaries and pipe burial based on temperature profile differential over the pipe length. One manufacturer offers hollow cores within the structure of the flexible pipe such that a limited length of fibre optic cable can be 'blown down' the core to allow for monitoring at a later date if required. This may reduce capital investment in the flexible whilst still allowing for future installation of monitoring fibres if circumstances later dictate that improved monitoring is required.	

Industry Practice
Although fibre optics have been offered as an installation option for a number of years the increased CAPEX has resulted in only a limited number of in-service flexible pipes being installed with fibre optic monitoring capabilities. One operator reports having positive experiences with using fibre optic temperature monitoring although feedback from the wider industry was limited.
Guidance Note
All manufacturers of flexible pipe offer fibre optic monitoring to varying degrees, however, the CAPEX involved has, to date, resulted in limited industry up-take. Consideration should be given to fibre optic temperature monitoring of risers where the operational and / or environmental conditions are close to the design limits of operation. A factor in considering this monitoring technology is the topsides interface in terms of restricted / zoned area, power supply, data transfer / logging and maintenance requirements, although these can all be managed and accounted for at the design stage.

Table B.18 Technology Review – Pressure Monitoring – Inline

Inspection / Monitoring / Technology Name	Pressure Monitoring - Inline
Technology Readiness Level (TRL) (Range 1 to 7)	7
Take-Up (Range 1 to 5)	5
Industry (JIP) Feedback (Range 1 to 5)	4
Summary	
Basic measure to monitor bore pressure.	
Benefits	**Limitations**
• Basic verification that operations are within design / operating limits, for both extreme and fatigue design • Several threats are linked to the internal bore pressure, monitoring of the pressure allows for mitigation/control or assessment of these threats.	• Where pressure is monitored from topsides equipment, a basic assessment should be made on wellhead pressure to obtain correlation for each flowline or riser. • Some pressure sensor fittings can be subject to vibration risks due to FLIP.
Procedure	
Monitoring of the bore pressure is predominantly performed using standardised sensors located in the topsides facilities and/or from locations upstream of the flexible pipelines, i.e. templates, wells, manifolds	
Industry Practice	
Monitoring of bore pressure varies across the industry but remains an important parameter in global design compliance and in the verification of fatigue damage. Historically, some operators recorded pressure data on an excursion basis, such that only values above or below pre-defined limits were recorded. However, this is now a rarity with operators, with most utilising data logged in a data acquisition system, which provides warning and alarm levels, and can also be interrogated at a later date for life extension studies or integrity reviews. The pipeline pressure trip setting is normally set to limit bore pressure at/below the system MAOP. Care should be taken to ensure that where topside monitoring equipment is used, subsea differential pressures are extrapolated to ensure compliance with design limits. This is more pertinent in deep water applications where significant pressure differences can occur as a result of hydrostatic head. Guidance is provided in Ref. [16] for a minimum sampling rate of a 1-hourly mean temperature, though recommends actual intervals and frequencies are based on a specific risk assessment. A 1-hourly sampling rate is likely to be excessive for lower risk pipes. Higher sampling rates are normally used for lines where the control of depressurisation rate is more critical, such as where multilayer pressure sheaths are employed. Several operators sample data at higher frequencies which has proven to be beneficial when completing specific assessments. The	

ability to retrospectively interrogate data at different frequencies requires logging of the full history with a high sampling rate. The sampling rate and monitoring / review frequency should be risk based, and reviewed once a baseline has been established.
Guidance Note
Bore pressure is a basic monitoring requirement and forms a significant part of the recommendations laid out in API TR 17TR16 Ref. [12]. Data should reflect each individual flexible pipe; where the inlet pressure is from the wellhead, pressures should also be monitored at this location. If pressure is monitored from the topsides separator vessel and no direct pipe pressure monitoring is performed, then a basic assessment should be made on wellhead pressure to obtain some form of correlation for each flowline or riser. It is recommended that continuous monitoring and as a minimum daily logging (typically minimum, mean, maximum) of the pressure should be performed to provide detail on the normal operating conditions. Any excursions outside of the defined anomaly limits should be identified and assessed. For cases where pressure pulsation and/or slugging effects occur, more frequent pressure recording should be implemented. There are multiple observed cases of dynamic risers being subject to slug-induced motions, however no damage or failure cases have been directly attributed. Differential pressure monitoring may be used at both ends of any pipe section to detect or assess restriction / reduction in the nominal bore e.g. from wax / sand blockage, hydrate formation, major dents, carcass collapse / significant damage. However, it should be noted that minor changes in the nominal bore may be challenging to detect using this approach. For cases where depressurisation is more critical (e.g. smooth bore pipes and multilayer pressure sheaths), monitoring should allow for recording of maximum rates of change as well as overall magnitude of pressure.

Table B.19 Technology Review – Pressure Testing (Hydro Testing)

Inspection / Monitoring / Technology Name	Pressure Testing (Hydro Testing)
Technology Readiness Level (TRL) (**Range 1 to 7)**	7
Take-Up (**Range 1 to 5)**	5 (design FAT onshore and offshore leak test) 3 (in service)
Industry (JIP) Feedback (**Range 1 to 5)**	3
Summary	
Water is pumped into the bore of the flexible pipe to raise the pressure and confirm the pressure containment capability of the flexible pipe.	
Benefits	**Limitations**
• Able to confirm pressure containment capability following incidents (at time of test). • Recognised across industry as a standardised testing approach.	• May fail the riser during testing, although failure is "controlled" to minimise risk. • Does not provide ongoing confirmation of integrity unless test is repeated. • Provides limited information on the armour wire condition, particularly in systems with high levels of designed redundancy. • Does not provide any assurance on carcass condition.
Procedure	
Offshore pressure testing is performed to demonstrate the integrity of the flexible pipe in compliance with industry standards and specifications. A leak test is typically performed at 110% of the Maximum Allowable Operating Pressure (MAOP) of the system as part of commissioning. If damage is suspected Ref. [1] recommends testing to 125% of design pressure where possible. The criteria for passing the test are met by the stabilisation of the pressure over a defined period. Hydro-testing is also routinely completed at 150% of design pressure (125% for static applications) to validate the manufacture of the pipe during factory acceptance testing.	
Industry Practice	
This technique is applied to all systems to demonstrate leak integrity after installation, commissioning and following any periods where the flexible was disconnected / reconnected. There are instances where operators use this method to demonstrate immediate integrity of systems, most frequently relating to post incident confirmation of fitness for service. The pressure test, however, does not provide any information on the condition of the remaining wires other than to confirm that at the time of testing there were sufficient armour wires remaining to prevent failure. It is known that at least one operator has experience of flexible pipes failing in the immediate period (weeks) after completing a	

'successful' hydro test. This proves to reinforce that hydro testing, whilst having its benefits, cannot be used to provide long term integrity assurance of flexible pipes. Another operator reported failure of a riser during pressure test activities conducted in response to corrosion integrity concerns.
Guidance Note
Whilst API RP 17B [1] advises testing at 125% of design pressure following an incident to validate integrity, it is known that where the pipe is intended to operate at a pressure lower than designed some operators have completed hydro-testing at lower than design pressures. This "de-rating" approach allows a degree of confidence to be achieved to continue operation whilst minimising the risk of failing a pipeline during testing by exposing it to pressure that it is unlikely to, or cannot, experience during operation. Whilst hydro testing can confirm that sufficient armour wires are present at the time of testing to prevent failure (assuming the test itself does not fail the riser), it does not provide any additional information on the condition of the armours or the number of failed wires, particularly in structures that have a high level of redundancy in the design. As such, it does not provide a long-term confirmation of the integrity of the flexible pipe, and therefore its use to demonstrate assurance of dynamic risers where fatigue effects may dominate is limited.

Table B.20 Technology Review – Topsides – Annulus Vent Systems Inspection

Inspection / Monitoring / Technology Name	Topsides – Annulus Vent Systems Inspection
Technology Readiness Level (TRL) (Range 1 to 7)	7
Take-Up (Range 1 to 5)	3
Industry (JIP) Feedback (Range 1 to 5)	5
Summary	
The main intent of this inspection is to ensure that an unrestricted vent path exists to allow venting of permeated gasses through the topsides end fitting for all risers. De-aerated WI lines are unlikely to require ongoing venting, although access to the annulus for annulus monitoring may be of significant benefit (Refer to Table B.22).	
Benefits	**Limitations**
• Confirms free venting of the riser annulus. • Confirms potential flow rate limitations of the installed system (insufficient rate of through flow can lead to annulus pressure build up).	• Requires safe and independent access to the vent system.
Procedure	
Inspection should ensure that a clear and free vent path exists, as follows: • if an annulus pressure gauge is present, the pressure should be recorded • any in-line valves should be verified as being open, and registered in a locked open / closed register • if NRV's / PRV's are present, their functionality should be verified, or they should be replaced • record any corrosion products, externally or retrieved via drain points, or other damage for remediation	
Industry Practice	
Normal good practice is to perform this maintenance activity annually. It is often performed in conjunction with an annulus testing campaign, when the end fitting vent ports can also be verified as being free and clear.	
Guidance Note	
Verifying that a clear annulus vent path exists is critical to annulus integrity as it mitigates the risk of annulus over pressure and failure of the outer sheath. There have been several historic reports where multiple risers have been partially or fully flooded as a result of fluids flowing into the risers from a comingled or common vent system. Good practice utilises NRVs between the individual risers and the vent header to mitigate against this risk. There is recent failure experience (three events) attributed to cyclic backflow of moisture / atmospheric air, leading to catastrophic corrosion failures within the end fitting which would have been prevented had NRVs been installed.	

Table B.21 Technology Review – Topsides – Annulus Testing

<table>
<tr><td>Inspection / Monitoring / Technology Name</td><td>Topsides – Annulus Testing</td></tr>
<tr><td>Technology Readiness Level (TRL) (Range 1 to 7)</td><td>7</td></tr>
<tr><td>Take-Up (Range 1 to 5)</td><td>5</td></tr>
<tr><td>Industry (JIP) Feedback (Range 1 to 5)</td><td>4</td></tr>
<tr><td colspan="2">Summary</td></tr>
<tr><td colspan="2">Annulus testing is normally performed to verify the integrity of a riser outer sheath through the ability to maintain a stable differential pressure between the annulus and the external environment, and annulus volume verification. Annulus testing can only be completed in risers that have accessible vent ports that provide a path to the annulus.

Two methodologies exist for annulus testing, namely vacuum testing and positive pressure testing. Both methods rely on introducing a known volume of gas, typically Nitrogen, to the annulus and monitoring the effect this has on the annular pressure. The change in pressure resulting from the injection of a known volume of gas is used to identify the free volume within the annulus which is compared against the design, FAT volume, or previous test result.

See also Table B.23 Subsea Annulus Testing / Monitoring.</td></tr>
<tr><td>Benefits</td><td>Limitations</td></tr>
<tr><td>• Verifies outer sheath integrity, allowing (higher cost) subsea inspections to focus on risers with compromised annuli.
• Vacuum method readily allows gas sampling.
• Blanketing of nitrogen following vacuum test gives ongoing protection for a limited time afterwards.
• Testing can be completed irrespective of operational status of the riser.</td><td>• Provides a 'snapshot' of outer sheath integrity at the time of testing only.
• Incorrect testing may damage the riser.
• Breach location identification typically limited to around -30 m maximum water depth (3 barg positive pressure).
• Interpretation of results often required to identify status of riser annulus.
• Cannot detect condition of armours within the annulus (only confirms dry/flooded condition).</td></tr>
<tr><td colspan="2">Procedure</td></tr>
<tr><td colspan="2">For both test methodologies a permeation rate for the riser is identified so that it can be accounted for in subsequent volumetric calculations. A known volume of nitrogen at low pressure is then flowed into the annulus (in the case of vacuum testing a partial vacuum is drawn in the annulus prior to injection of nitrogen). The annulus pressure is allowed to stabilise and the new pressure recorded. The process of nitrogen injection, stabilisation and pressure recording is repeated allowing the annulus free volume to be calculated based on the increase in stabilised pressures over known control volumes. Once testing has been completed, the annulus should be returned to</td></tr>
</table>

ambient pressure by either venting nitrogen from the annulus (positive pressure testing) or injecting additional nitrogen (vacuum testing). The stabilisation criteria and operational condition must be documented in a procedure to ensure a consistent approach for subsequent tests. Where flooding is detected to the waterline, larger volumes of nitrogen at up to 3 barg can be injected to raise the annulus pressure sufficiently to confirm if the breach exists within the splash zone where oxygenated seawater can pose a significant corrosion threat to the armour wires.
Industry Practice
Most operators perform some form of periodic (risk based) annulus monitoring, with annulus testing being the most commonly applied method. It is normal for dry bottled nitrogen to be used as the test medium for both vacuum and positive pressure approaches. Helium-traced nitrogen, and appropriate gas detectors, have been used to aid leak detection around connections / fittings or to identify the presence of slow leaks within caissons, I-tubes or under bend stiffeners. Indeed, some operators permanently install gas detectors within caissons / I-tubes to identify the presence of annulus gases which would indicate an outer sheath failure within the caisson / I-tube. A smaller proportion of operators who perform annulus testing elect to perform annulus gas sampling as a parallel activity i.e. take-up for gas sampling is significantly lower than the take-up for annulus testing.
Guidance Note
The risk of over-pressurising a riser annulus during testing must be carefully managed to avoid causing damage to a potentially weakened outer sheath. Typically, the riser annulus design pressure is circa 3 barg, although it is known that most intact/undamaged sheaths do not fail below circa 7-10 barg. Given that the test intent is to validate integrity, a degree of caution is required in applying excessive positive pressures to ensure damage is not caused inadvertently. Performing a vacuum test prior to any positive pressure testing can verify the outer sheath integrity which negates the requirement to apply any positive pressure, thereby minimising the risk of causing damage during testing. Most test procedures limit positive pressure application to 2-3 barg which still allows for the identification of breaches within the oxygenated riser splash zone. It is good practice to complete an annulus volume measurement on the flexible pipe at FAT and following installation to allow for comparison against through life inspections. There is experience that bore pressure can impact the results of free volume annulus testing, e.g. test results of in service risers (pressurised bore) can return lower free volumes than a non-operational de-pressurised riser. Gas samples from the annulus can be collected and analysed to identify the risk of corrosion and embrittlement to the tensile and pressure armours. The volume of gas required for sampling can be collected through controlled pressure build up, by temporarily isolating the riser vent path whilst monitoring pressure increase, or by using a vacuum pump to actively draw out gas from the annulus. However, it should be noted that corrosive gases may react with the armour wires before they reach the vent system. As such, the absence of a gas from a sample (e.g. H_2, H_2S, CO_2) should not be taken as confirmation that the armour wires have not been exposed to that gas.

Table B.22 Technology Review – Topsides – Annulus Monitoring

Inspection / Monitoring / Technology Name	Topsides – Annulus Monitoring
Technology Readiness Level (TRL) (Range 1 to 7)	7
Take-Up (Range 1 to 5)	3
Industry (JIP) Feedback (Range 1 to 5)	4
Summary	
This technology review is "by exception / difference" to the related "Topsides – Annulus Testing" from Table B.21. Many different systems exist with varying capabilities however all utilise continuous monitoring of specific key annulus characteristics (e.g. pressure, temperature, permeation rate, gas composition etc.) to monitor the annulus condition.	
Benefits	**Limitations**
• Similar to other forms of annulus testing, may allow (higher cost) subsea inspections to focus on risers with compromised annuli. • Identifies changes in flow rate in real time e.g. may indicate vent port blockage or bore leaks. • Some systems complete annulus gas composition assessments (lower TRL). • Can provide online notification of outer sheath breaches. • Can reduce/remove requirement for periodic annulus testing, subject to risk assessment and confidence in obtained results.	• Validation of results (e.g. flooding) may be required through annulus testing. • Equipment reliability and requirement for periodic maintenance. • Potential to damage the riser if vent path is blocked through failure of the monitoring system.
Procedure	
The monitoring system is connected into the riser vent system between the end fitting vent ports and the vent exhaust/flare system. The system monitors and analyses the vent gases and is usually linked to a viewing panel in the control room where alerts and alarms are displayed/managed.	
Industry Practice	
A number of operators have installed retro-fit online monitoring solutions to their existing risers whilst other operators specifying that all newly installed risers will be equipped with monitoring equipment. Several operators had historically described difficulties in obtaining accurate results from monitoring equipment as a result of low volume flow rates coming from the annulus. Improvements to the monitoring systems have allowed for these initial	

reliability issues to be removed and feedback is now generally positive across users to identify changes in the annulus condition. One operator reported that alarms have been triggered falsely from spurious results obtained during shutdown and start-up periods. The monitoring equipment supplier was able to recalibrate the monitoring system to take account of these situations to prevent further alarms being triggered in error. An additional operator hypothesised that systems which maintain an increased annulus pressure (e.g. 1.8barg at annulus topsides) may increase condensation rate in the annulus, and was believed to be a contributory factor in annulus fluids accumulating at the sag bend.
Guidance Note
One of the key benefits of a continuous monitoring system is its ability, when compared to periodic annulus testing, to more rapidly identify annulus flooding. This allows for a more rapid response and in the case of external sheath breaches, can minimise the duration that the annulus is exposed to seawater ingress by allowing the early identification of repair options. Furthermore, having a more accurate understanding of when the breach occurred allows for more accurate corrosion / fatigue assessments to be completed. As discussed previously (Table B.21), care must be taken when directly using the composition of gas samples from the annulus to complete corrosion / embrittlement assessments of the armour wires.

Table B.23 Technology Review – Subsea Annulus Testing / Monitoring

<table>
<tr><td>Inspection / Monitoring / Technology Name</td><td>Subsea Annulus Testing / Monitoring</td></tr>
<tr><td>Technology Readiness Level (TRL) (Range 1 to 7)</td><td>6</td></tr>
<tr><td>Take-Up (Range 1 to 5)</td><td>1</td></tr>
<tr><td>Industry (JIP) Feedback (Range 1 to 5)</td><td>N/A</td></tr>
<tr><td colspan="2">Summary</td></tr>
<tr><td colspan="2">This technology review is "by exception / difference" to the related "Topsides – Annulus Testing" from Table B.21.

Historically, annulus testing was only able to be completed via the accessible vent ports fitted to the topside riser end fitting. This limited the ability to identify the breach location in damaged risers to the binary selection of within or below the splash zone. Recent developments include a subsea manifold which, when installed between riser or flowline end fittings (typically deep water applications only), permits annulus monitoring and testing of the individual pipe segments. Testing of individual segments and the recovery of monitoring data is achieved through ROV intervention.</td></tr>
<tr><td>Benefits</td><td>Limitations</td></tr>
<tr><td>• Allows breach locations to be identified within individual pipe sections.
• Allows monitoring of the outer sheath integrity of seabed flexible flowlines as well as risers.</td><td>• Integrated solution (not possible to retro fit).
• Requires ROV intervention to recover monitoring data and perform testing.
• System adds additional mass and rigidity to the flexible at the segment interfaces.</td></tr>
<tr><td colspan="2">Procedure</td></tr>
<tr><td colspan="2">The annulus control manifold is installed between the end fittings of adjacent pipe segments during the initial pipe installation. The system allows access and intervention to the individual annuli of the pipe without interfering with the bore flowpath. Following installation, the system allows for the continuous monitoring of the annulus parameters such as pressure and temperature with the ability to sample annular fluids to identify their content; recovery of the data is achieved by ROV data download. The ROV manipulatable manifold controls allow the annulus of each pipe segment to be either isolated, enabling pressure purging and inert fluid injection, or connected to the adjacent pipe segments annulus to create a continuous vent path to the topside vent ports. Localised purging of individual pipe segments annuli (to sea or to topside via ROV umbilical) may be achieved to create an annulus circulation path which enables fluids within the annulus to be displaced and replenished.</td></tr>
<tr><td colspan="2">Industry Practice</td></tr>
<tr><td colspan="2">Take up of the technology is currently limited with the first system installed in 2021. Initial feedback has been positive, however longer-term trialling of the system is still ongoing.</td></tr>
</table>

Guidance Note
The differential pressures between external hydrostatic head (water column) and fluid injection pressures need to be closely managed to prevent the risk of over-pressurising the riser annulus during injection procedures.

Table B.24 Technology Review – Vent Port Unblocking

Inspection / Monitoring / Technology Name	Vent Port Unblocking
Technology Readiness Level (TRL) (Range 1 to 7)	6
Take-Up (Range 1 to 5)	1
Industry (JIP) Feedback (Range 1 to 5)	N/A
Summary	
A means of using small volumes of pressurised fluids to attempt to regain communication between the end fitting vent ports and the riser annulus.	
Benefits	**Limitations**
• Allows vent path to be maintained. • Unblocked ports allow means of conducting routine annulus tests.	• Success rate will depend on the level of restriction and the root cause of the restriction. • Chemical compatibility needs to be confirmed with polymers and steels.
Procedure	
A small volume of chemical solution is driven into the restricted/blocked vent port with pressure supplied from an isolated low volume reservoir which can be filled to variable pressures.	
Industry Practice	
Many operators have reported issues with vent port systems becoming progressively restricted or blocked during the service life of the risers. Where risers are fitted with multiple vent ports it is not uncommon for one or more of the vent ports to suffer from a restriction of some sort up to and including full blockage. Historically efforts to regain communication with the annulus have included the application of pressure (typically nitrogen gas at up to 3 Barg), which had varying degrees of success.	
Guidance Note	
For pipes carrying gas or multiphase fluids where it is likely that permeation will occur between the bore and the annulus it is essential to main a vent path to prevent over pressurisation of the annulus and resultant outersheath breach. Risers are typically designed with multiple vent ports so that there is redundancy should one port become blocked. Monitoring of the condition of the vent ports and vent system (See Table B.20) during routine annulus testing is recommended to allow intervention activities to be undertaken in a timely manner prior to total blockage of the vent arrangement occurring. Care must be taken to ensure that no damage to the riser occurs during unblocking attempts (e.g. over pressurisation).	

Table B.25 Technology Review – Ultrasonic Inspection

Inspection / Monitoring / Technology Name	Ultrasonic Inspection
Technology Readiness Level (TRL) (Range 1 to 7)	7
Take-Up (Range 1 to 5)	4
Industry (JIP) Feedback (Range 1 to 5)	4
Summary	
An ultrasonic probe / sensor is directed towards the outer sheath layer and the responses recorded to provide an indication of a flooded annulus and where visible the condition of the outer armour wires.	
Benefits	**Limitations**
• Method provides an indication of whether annulus is flooded at the scan location. • Allows an alternate methodology for confirming annulus condition (flooded/dry) in risers where vent ports are blocked or not installed. • Where coupling is achieved, outer armour wires become visible and defects such as necking, fracture or disassociation of the armour wires at the scan location may be identified.	• Requires access to outer sheath at scan location, and existing tools require full circumferential access. • Passivity of polymer outer layers reduces effectiveness of UT probes and clarity of the underlying image. • Surface finish/cleanlinesss of the polymer outer sheath can impact the effectiveness of the deployed technology. • Relies on the presence of a couplant to present an image of the armour wires. e.g. cannot assess above water level. • False indication of flooding may arise where coupling is achieved due to high contact loads between outer sheath and tensile wires or where moisture is present in the annulus, e.g. wetted but not flooded. • May not be applicable in cases where insulation or multiple external sheath layers are present.
Procedure	
The procedure for the UT of flexible pipes is very similar to the approach used to inspect rigid pipework. An ultrasonic test head is scanned around the outer sheath of the flexible pipe. Where an acoustic couplant is present in the annulus, the ultrasonic signals pass through the couplant and 'reflect' from the outer tensile armours and provide an image of the surface.	

The UT tools can be deployed directly by a diver (where depth constraints allow), by an ROV where the tool is mounted into a frame, or with the tool mounted to a crawler. Once an image has been obtained various methods exist to interrogate the image to identify armour wire remaining thickness and characteristics.
Industry Practice
The use of ultrasonics, and specifically normal beam scanning, has been applied to flexible pipe as far back as 1994 and has been a continued area of research and development since this time. Several UT inspection tools are now available and have been deployed to varying degrees of success. Some vendors have demonstrated an ability, in flooded risers, to reliably identify armour wire characteristics such as disassociation, surface corrosion, material loss and fracture/breakage. The system relies on the presence of a couplant to allow an image of the armours to be produced. This has led to the use of the tool to identify the presence of couplants (e.g. seawater) within the annulus to confirm if the annulus is flooded.
Guidance Note
UT inspection tools can play a valuable role in confirming the fitness for service of flexible pipe, particularly in risers or exposed flowlines where the full circumference of the pipe is accessible to allow the inspection tools to be deployed. Inspection of pipe section under the bend stiffener, buoyancy modules or within sealed I/J-tubes cannot be inspected due to access constraints. The polymer outer sheath material of flexible pipes does not readily lend itself to the transmission of the ultrasound frequencies. Lower frequencies of ultrasound have a higher penetration capability through the outer polymer layer but produce a lower definition image than higher frequencies which have reduced penetration capabilities. The thickness of the polymer outer sheath therefore impacts on the resolution and clarity that can be achieved. To date, successful inspections have been completed through double layer outer sheaths with a combined thickness in excess of 22 mm. In limited onshore testing two vendors identified cases where they obtained UT transmission in pipe sections which were not necessarily deemed to be fully flooded, but a possibility of moisture ingress. excess grease or oils acted as a couplant. As such a degree of caution must be applied when using UT test equipment to identify flooding of the annulus.

Table B.26 Technology Review – Electrical Outer Sheath Breach Detection

Inspection / Monitoring / Technology Name	Electrical Outer Sheath Breach Detection
Technology Readiness Level (TRL) (Range 1 to 7)	5
Take-Up (Range 1 to 5)	1
Industry (JIP) Feedback (Range 1 to 5)	N/A (not deployed)
Summary	
Two discrete forms of detection tools exist, one which relies on a series of embedded / integrated sensors within the pipe structure / end fitting and a second retrofit inspection tool deployable from the asset via micro ROV. Both techniques are capable of confirming the presence of historic flooding within the riser. The embedded sensor option can be used to complete on demand inspection or continuous monitoring whilst the retro fit solution only offers a snap-shot of outer sheath integrity.	
Benefits	**Limitations**
• Neither tool requires vent port access to confirm annulus condition. • Designed to provide rapid test results. • Can be utilised for either continuous monitoring or point in time testing.	• Monitoring requires sensors to be defined at the design stage and built into the riser, impacting CAPEX. • Periodic testing (embedded option) cannot identify breach location or size of breach. • Continuous monitoring requires cabling to be permanently installed from the riser to a control station.
Procedure	
Both systems operate based on conductivity and rely on an electrolyte (typically sea water) to complete the circuit and provide an indication of flooding and the associated breach. **Embedded Sensors**: The procedure for electrical breach detection involves integrating sensors and cabling into the flexible pipe structure during manufacture which make it possible to either continuously monitor or test for flooding of the annulus. Specially designed electrical bolting is integrated into the end fitting of the riser to allow for inspection or monitoring equipment to be connected. In the case of continuous monitoring these connections are permanently wired back to a control station where status alerts and alarms are displayed. If a breach occurs during continuous monitoring (embedded sensor option), the location of the breach may be identified. Variations in the conductivity of seawater and permeated fluids allows for the embedded sensors to differentiate between seawater flooding and progressive filling of the annulus space through fluid permeation. **Retrofit Inspection**: The procedure relies on attempting to create an electrical circuit between the riser and a ROV mounted probe. Low energy high bandwidth electrical signals are sent via the topside end fitting into the metallic	

layers of the flexible. Where a breach in the outer sheath exists, the signals are conducted through seawater and are detected by the probe attached to the ROV when it comes within range of the breach location.
Industry Practice
This manufacturer provided option offers an additional or alternative monitoring technique to integrated fibre optics to identify flooding of the annulus. To date the embedded sensor system has not been deployed in the field, however has been subjected to significant onshore testing and validation and indications are that minimal additional work would be required in order to deploy in the field. The retrofit inspection solution has undergone sea trials but is still pending first operations deployment.
Guidance Note
With no operational track record of deployment, there is no available experience to report. The system requires power and communications provision throughout its service life (for the continuous monitoring option) which will require cabling to be located in the hang-off / turret area. Whilst this additional cabling should not present a significant obstacle to the deployment of the system, care will be required at the design stage to confirm that power supplies and communication paths are available.

Table B.27 Technology Review – Fibreoptic Armour Wire Inspection (End Fitting)

Inspection / Monitoring / Technology Name	Fibreoptic Armour Wire inspection (End Fitting)
Technology Readiness Level (TRL) (Range 1 to 7)	5
Take-Up (Range 1 to 5)	1
Industry (JIP) Feedback (Range 1 to 5)	N/A
Summary	
Inspection of the outer tensile armour wires immediately adjacent to the vent port annulus access using fibreoptic inspection cameras where there is a threat of localised armour corrosion as a result of having an open/breathing vent system.	
Benefits	**Limitations**
• Can provides indication of localised armour wire condition at the tip of annulus vent tubing within the end fitting.	• Only provides very localised inspection capability of a limited number of outer tensile armour wires. • Cannot confirm the presence of corrosion on wires not adjacent to the vent port tubing.
Procedure	
A small bore fibre optic inspection camera, complete with self-contained light source, is inserted via the vent port on the riser end fitting and progressed through the tubing to the interface point with the annulus.	
Industry Practice	
Deployed in a very limited number of cases where there was concern of localised armour wire corrosion within the end fitting as a result of corrosive fluid ingress via the vent system. Output is a basic visual inspection, i.e. clean bright wires vs corrosion product evident. Systems may also additionally incorporate a vacuum pump for localised cleaning.	
Guidance Note	
The flow path between the annulus and the exposed vent port often includes numerous machined fixtures and lengths/bends of small-bore tubing. Where access through the vent port for visual inspection is required it will be necessary to obtain the detailed end fitting design drawings from the manufacturer to ensure that the inspection equipment is sized appropriately to navigate the vent path and the risk of the inspection tool becoming lodged within the vent port is appropriately managed.	

Table B.28 Technology Review – Clamped Outer Sheath Repair

Inspection / Monitoring / Technology Name	Clamped Outer Sheath Repair
Technology Readiness Level (TRL) (Range 1 to 7)	7
Take-Up (Range 1 to 5)	3
Industry (JIP) Feedback (Range 1 to 5)	4
Summary	
An external clamp arrangement that is applied over areas of damage on the outer sheath to reseal the annulus and prevent further fluid replenishment (oxygenated seawater / air).	
Benefits	**Limitations**
• Prevents further fluid replenishment (seawater or air) from entering the annulus reducing the likelihood of continued corrosion. • Clamps can be scaled such they encapsulate varying sizes of defects in the outer sheath.	• Ability to install within I-tubes or around ancillary equipment such as buoyancy modules, bend stiffeners or mid water arches, may be limited. • Clamps may interfere with and prevent the use of externally applied non-intrusive inspection techniques to confirm the condition of underlying structural components. • Long lengths of damage may not be suitable for clamp application. • Localised increases in stiffness at the clamp location could lead to localised fatigue loading.
Procedure	
Following detailed inspection and removal of debris or flared sections of the outer sheath, an appropriate clamp is selected/designed and installed either by diver or ROV. The clamps, typically bolted designs, are tightened against undamaged areas of the outer sheath on either side of the damaged section to create a water or atmospheric tight seal. Following installation the annulus may be tested to confirm if an appropriate seal has been achieved. The design requirements and recommended practices for flexible pipe clamps are captured within Ref. [2] and [5].	
Industry Practice	
Commonly deployed in dynamic applications where localised sheath damage has been identified and there is a concern that fluid replenishment may lead to localised corrosion of the armour wires.	

Guidance Note
Annulus flooding is the leading damage mechanism related to flexible pipes with breach location typically identified through a combination of annulus testing and visual inspection techniques. Breaches in the outer sheath within the air zone or oxygenated splash zone are of specific concern due to the threats associated with accelerated corrosion of the armour wires. Clamping of these breaches is therefore recommended and has been accompanied by the injection of inhibition chemicals into the annulus to arrest continued corrosion by a limited number of operators. Breaches at depths where oxygenated corrosion of the armours is considered unlikely, may not benefit from the application of clamp arrangements unless the application of the clamp prevents continued flooding of the annulus to mean sea level. However, it should be noted that in such cases where the annulus is slowly progressively flooding, the breach is likely to be very small and identification of the breach location is likely to be challenging. The use of chemical dyes and ROV/diver assisted visual inspection may aid with the identification of small breaches, however this process is time consuming and challenging as the restricted annulus environment can impede the flow of chemicals introduced from topsides. It is essential to ensure that any fluids/chemicals injected into the annulus are compatible with all layers of the pipe structure to prevent introducing additional potential damage mechanisms.

Table B.29 Technology Review – Polymer Coupon Monitoring

Inspection / Monitoring / Technology Name	Polymer Coupon Monitoring
Technology Readiness Level (TRL) (Range 1 to 7)	7
Take-Up (Range 1 to 5)	4
Industry (JIP) Feedback (Range 1 to 5)	4
Summary	
Polymer coupon monitoring, primarily focussed on internal pressure sheath materials, is utilised to estimate the current condition and to predict future degradation of the polymer layer. Some experience of monitoring external sheath coupons has been seen for pipes that are planned for long term storage. Monitoring is achieved through assessment of the molecular weight / viscosity of retrieved coupons to predict remaining service life and may also include compression/tensile testing. All polymer variants can be monitored utilising this methodology.	
Benefits	**Limitations**
• Verifies the integrity and ageing characteristics of polymer materials. • Established technique backed by industry guidance (API 17 TR2).	• Sampling usually performed topsides for production systems (cold end), resulting in underestimation of polymer degradation in (hot end) well production jumpers. • Difficulties can exist with extrapolation of results from topsides sampling to subsea degradation due to co-mingling of flows • Some concerns raised regarding API 17 TR2 in specific cases (currently subject of ongoing JIP to review / update).
Procedure	
This method involves periodic removal and sampling of material coupons that have been placed in the product stream to assess the state of polymer degradation. The samples (ideally from the original material batch) are commonly placed in a rack system in the process stream. Mechanical and hydraulic systems are available which allow on-line retrieval of coupons.	
Industry Practice	
Historically, polymer coupon testing was limited to PA-11 only, however the use of polymer coupons for other pressure sheath materials have been adopted for new systems by some operators. Sampling is normally performed at the topsides facility using ladder rack holders, and involves subsequent laboratory analysis of the samples. A limited number of operators have reported utilising subsea deployed coupons, although access for retrieval is costly. It is known that at least one service provider also monitors for outer sheath degradation of risers in long term	

storage using polymer coupons taken from the parent outer sheath material. Testing methodologies vary both in terms of the polymer type and also across operators and test houses.
Guidance Note
Polymer degradation is fundamentally linked to the bore fluid composition and the temperature to which the polymer is exposed. Therefore, it is good practice for operators to utilise monitored data to identify when coupons should be retrieved as part of the integrity management strategy. The frequency of retrieval needs to be set on a suitable safety factor associated with the uncertainty of the polymer life. It is recommended to ensure that adequate coupons remain available at end of original design life to allow for potential life extension assessment activities. In line coupons have the advantage of allowing validation of the potentially conservative theoretical results of desktop degradation studies which, when viewed in isolation, could result in the premature removal from service of a flexible pipe. The assessment of polyamide coupons should be completed in line with API 17 TR2, refer to Section 8.4 for further details. Polymer coupon monitoring should not be used to form the basis of argument against continued bore fluid composition monitoring, rather the two techniques should be viewed as a complimentary.

Table B.30 Technology Review – Bore Fluid Sampling

Inspection / Monitoring / Technology Name	Bore Fluid Sampling
Technology Readiness Level (TRL) (Range 1 to 7)	7
Take-Up (Range 1 to 5)	4
Industry (JIP) Feedback (Range 1 to 5)	5
Summary	
Samples taken from the bore are analysed to identify the bore fluid composition. Results are frequently compared against KPIs based on the fluid composition considered during design and/or are used as inputs for further assessments. Similarly, the efficacy of injected chemicals may be identifiable (depending on the location of the sample collection point).	
Benefits	**Limitations**
• Basic monitoring technique, widely deployed across the industry. • High level of confidence in obtained results. • Outputs of sampling routinely provide the inputs to further analysis work. • Allows for validation of designed exposure criteria.	• Delays between collection of samples and testing can lead to spurious results. • Sample locations need to be monitored to ensure they are representative of the system e.g. where comingling exists. • Care must be taken to ensure that samples are, where possible, maintained at bore pressure so as to identify dissolved gas composition, or pressure changes accounted for by other means.
Procedure	
A small sample of fluid is collected from the flow and analysed on the asset where facilities exist, or sent to a remote laboratory for analysis. Online bore fluid monitoring solutions exist for gas systems, utilising gas chromatography to identify the concentrations of gases within a sample. Online monitoring systems, once installed, collect samples autonomously from the bore flow, mitigating the risks associated with breaking containment to manually collect a sample for analysis.	
Industry Practice	
Bore fluid sampling is a common practice throughout the industry with most operators completing periodic (risk based) sampling and analysis. Routinely, samples are tested in offshore laboratories to provide rapid indications of the fluid composition e.g. presence of H_2S, CO_2, H_2O, O_2, wax content etc. Where offshore assets cannot offer the full suite of analysis required, samples are sent to onshore test facilities for processing. Care must be taken to ensure that samples sent onshore for testing are suitably packaged and assessed within a known timeframe to ensure	

accuracy of results. Further analysis of the results can be required to align the results of the sample (taken from a topside location) with the situation that would be seen subsea where hydrostatic head and temperature variations can alter the composition of the sample e.g. increased dissolved state gases.
Guidance Note
Maintaining the integrity of a sample between collection and analysis is of specific importance to ensure that accurate and representative results are achieved. Historically, samples are known to have been sent in unsuitable containers, been left in direct sunshine, or suffered long delays between collection and sampling which has resulted in contamination of the sample and/or a change in the characteristics of the sample e.g. significant microbe count reductions, inability to identify content of gases dissolved into the fluid.

Table B.31 Technology Review – X-Ray Computer Tomography (CT)

Inspection / Monitoring / Technology Name	Computer Tomography (CT)
Technology Readiness Level (TRL) (Range 1 to 7)	7
Take-Up (Range 1 to 5)	1
Industry (JIP) Feedback (Range 1 to 5)	N/A[1]
Summary	
Several vendors offer competing X-ray based systems to produce a three-dimensional cross section of the flexible pipe.	
Benefits	**Limitations**
• Provides high resolution cross section images of inspected areas. • Image quality not adversely affected by the presence of bore fluids / scale / hydrates / wax etc., and can identify these different elements.	• Historically takes a long time to complete inspection over a significant area. • Requires full circumferential access. • Not suitable for investigations under ancillary equipment e.g. bend stiffener/buoyancy modules / clamps etc.. • Limited track record with unbonded flexible pipe.
Procedure	
An X-ray source and detectors are passed around the circumference of the pipe to collect images at high frequency through the pipe at different angles. The individual images are then compiled to create a 3D image of the cross section of the flexible. Signals are received via a continuous communication link, such that results are available in real time.	
Industry Practice	
The inspection of pipelines by X-ray tomography has been in development since the 1990s and has since 2013 been successfully used on rigid pipes, coated pipes, and pipe in pipe systems to identify internal corrosion and the presence of wax/hydrate deposits. The competing technologies have also been tested on flexible pipes and have demonstrated an ability to show disassociation, corrosion, machined defects and displacement of the tensile armours. Testing indicates that damage or defects to the pressure armour, pressure sheath, carcass and flooding of the annulus can be identified.	
Guidance Note	
There is limited experience of in-field inspections of flexible pipes. Recent developments include several vendors	

progressing with developing technologies in laboratory/onshore settings and marinization of the technology is currently limited to a single vendor, whilst others are progressing towards miniaturisation and marinization. The speed at which inspection can be completed means that the tools are not suitable for screening for defects but may be suited to inspect specific sections of interest e.g. around exposed breach locations or sections of pipe where over bending is believed to have occurred. Whilst the dimensions and functionality of the inspection tools precludes inspection under the bend stiffener or around buoyancy modules/clamps etc. they have the potential to deliver a very high standard of imagery.

Note 1. Field deployment of this technology for the inspection of flexible risers is extremely limited, as such industry feedback could not be provided.

Table B.32 Technology Review – Eddy Current Inspection

Inspection / Monitoring / Technology Name	Eddy Current Inspection
Technology Readiness Level (TRL) (**Range 1 to 7)**	7 (tensile armour), 5 (pressure armour)
Take-Up (**Range 1 to 5)**	2
Industry (JIP) Feedback (**Range 1 to 5)**	3
Summary	
Identification of variances in the eddy current field density to indicate anomalies within the metallic armouring layers of the pipe.	
Benefits	**Limitations**
• No couplant required (does not require a flooded annulus).	• Comparative technique. (Returned signals are compared against a library of images from calibration defects). • Cannot inspect beneath bend stiffener, within i-tube, or beneath other ancillary equipment. • Manual interpretation of results required, typically during post processing of the data.
Procedure	
The inspection device, attached to the outer sheath of the flexible, monitors the eddy current fields emitted from the tensile armour wires that are induced by a DC electromagnet in the tool. Defects present within the tensile armour layer cause changes in the eddy current field density. These changes in signal phase, amplitude and pattern are evaluated against a library of calibration data in order to identify the type of defect and condition of the armours. The tool requires clear access to the outer sheath and can be utilised to inspect topsides or subsea pipework to identify corrosion, pitting or transverse ruptures of the tensile armour wires.	
Industry Practice	
This method has been used for inspection of specific areas of interest where the external sheath of the flexible is accessible. Several tools exist that can be deployed from within the riser air zone or subsea by an ROV. Removal of marine fouling from the outer sheath is routinely required when completing subsea inspections (See Table B.8). Tooling has also been developed to allow inspection from inside the bore of the flexible however this relies on access to the bore being achievable and flushing/cleaning of the surfaces being completed prior to inspection and has a lower uptake than the external scanning option. Historically, multiple passes have been required in order to scan the inner and outer tensile armour layers with changes to the tooling required between scans; which has resulted in extended inspection durations. The obtained results subsequently required significant post processing and interpretation in order to return a result. Whilst	

feedback has been varied it is generally accepted that the technology can provide additional information on the condition of the tensile armours.
Guidance Note
There has been limited deployment of eddy current inspection technology to date. Where the tool has been deployed there has been variable feedback however operator feedback tends to be improving as the technology matures, although gaining confidence in the interpretation of results remains a challenge. The importance of preparing the riser surface prior to inspection is critical to inspection success.

Table B.33 Technology Review – Direct Strain Measurement

Inspection / Monitoring / Technology Name	Direct Strain Measurement
Technology Readiness Level (TRL) (Range 1 to 7)	6
Take-Up (Range 1 to 5)	2
Industry (JIP) Feedback (Range 1 to 5)	3
Summary	
A means of directly monitoring the strain present in the outer tensile armour wires of the flexible pipe (riser) to identify the presence of unloaded (broken) tensile armour wires. Inner wire damage may be inferred through a mean change in the outer wire loading.	
Benefits	**Limitations**
• Provides a direct measurement of the strain within each of the outer tensile armour wires. • Can identify tensile armours wires which failed prior to the installation of the monitoring equipment. • Results easy to interpret, minimal post processing and ambiguity in results.	• Only able to monitor the outer tensile armour wires directly. • Requires direct access to the outer tensile armour wires via localised removal of the outer sheath or specific end fitting design specified at time of manufacture. • Retrofit solutions require removal of a section of the outer sheath either within the air zone or accessed through the I-tube.
Procedure	
The monitoring system can be specified at design (specific end fitting required) or can be fitted retrospectively to existing equipment via the removal of a small section of outer sheath. Retrofit solutions (where the specific end fitting design is not fitted), requires the removal of a section of the outer sheath either circumferentially or longitudinally over the pitch length of the tensile wires to allow the sensors to be attached. Where retrofit installation is selected, installation typically takes place below the bend stiffener (for air zone bend stiffener risers) or by cutting an access window in the I-tube. Fibreoptic stress sensors are attached to each of the outer tensile armour wires via access points designed into the end fitting or through removal of a small section of the outer sheath within the above water section of the flexible pipe. Sensors are linked back to control system which presents the strain levels in each of the tensile armour wires allowing for variation in stresses to be identified which can indicate unloaded (broken) tensile armour wires.	
Industry Practice	
Although a relatively new monitoring technique it has been widely deployed by certain operators. A new design of end fitting has been developed to allow for ready access to the outer tensile armour wires allowing the monitoring	

system to be available from riser installation or fitted at a later date based on emerging requirements. All flexible pipe manufactures have indicated that they are able to manufacture pipes using the end fitting design where requested. Monitoring of the sensor outputs is collated to a central control system located on the asset, the data can be accessed locally via user interface or remotely by onshore office-based teams
Guidance Note
For the most reliable results it is anticipated that long term monitoring (from first installation) is likely to give the most accurate ability to detect changes in the riser armour wire loading. The monitoring system is designed to detect unloaded wires in the fatigue critical bend stiffener region up to the end fitting. Due to friction effects within the tensile armour wire structure, failures significantly below the bend stiffener (e.g. as a result of damage/corrosion within the water column or at the touch down point) are unlikely to be detectable using this technique.

Table B.34 Technology Review – Magnetic Stress Measurement

<table>
<tr><td>Inspection / Monitoring / Technology Name</td><td colspan="2">Magnetic Stress Measurement (unloaded wire detection)</td></tr>
<tr><td>Technology Readiness Level (TRL) (Range 1 to 7)</td><td>6 (inspection)</td><td>5 (monitoring)</td></tr>
<tr><td>Take-Up (Range 1 to 5)</td><td colspan="2">3 (inspection)</td></tr>
<tr><td>Industry (JIP) Feedback (Range 1 to 5)</td><td colspan="2">2</td></tr>
<tr><td colspan="3">Summary</td></tr>
<tr><td colspan="3">The inspection tool is connected to the outer sheath of the flexible riser and works by utilising the property of magnetostriction, whereby the magnetic field associated with each armour wire changes when a change in stress is applied to it. By generating different load cases in the riser (typically achieved through varying operational pressure) a comparison of the stress in each wire can be achieved for baseline inspections. Where an armour wire is not load bearing, the stress in the armour wire will not change when the loading in the riser is altered. For subsequent re-inspections, it may be feasible to perform the testing at a single load case as the structure variations have been calibrated for during the baseline inspection. However, subsequent multi pressure inspection may be required to increase confidence in results.</td></tr>
<tr><td>Benefits</td><td colspan="2">Limitations</td></tr>
<tr><td>Provides an indication of the loading in the tensile armour wires at time of inspection.
Can inspect under the bend stiffener and within the I-tube when tool located within reach/range (reach up to 15m)
Can normally specify if non-loadbearing wires are in the outer or inner tensile layers.
Can report the distribution of non-loadbearing tensile armours around the pipe circumference.</td><td colspan="2">Where a non-loadbearing wire is identified it cannot confirm if this is a breakage, design issue or as a result of riser interaction/contact loading with ancillary equipment e.g. not a wire break detection tool.
Requires different load combinations, e.g. applied internal pressure and / or change of internal fluid density, to calibrate the system (may require shutdown of operational risers to conduct baseline inspections).
Calibration and scanning historically required steady state operation. Heavy slugging may impact efficacy of the system.
Cannot identify wires that are close to failing.
Cannot identify exact axial position of wire failure, only that wire is unloaded within the detection range.
May struggle to identify single wire break and/or differentiate between single and adjacent failed wires.</td></tr>
</table>

Procedure
Two different deployment tools have been produced to allow for circumferential or longitudinal inspection of the riser. Both tools operate on the principal of scanning each of the individual wires to identify the stress level. Where access allows, traversing the tool around the circumference of the riser is preferred. However, for areas of restricted access, such as within caissons where access to the circumference of the riser cannot be achieved, similar results can be obtained by traversing the inspection tool along the length of the riser. In the case of longitudinal inspection, the pitch of the armour wires is taken into account to ensure that a sufficient length of riser is scanned to capture all of the armour wires. A monitoring option has also been developed that would allow a series of retro-fit sensors to be permanently installed to the riser to identify in real time changes to the loading of the armour wires. To date, the monitoring option has not been deployed offshore however, the technology has been tested onshore.
Industry Practice
The inspection technology has been used by multiple operators to inspect their risers and in cases where no or limited unloaded/broken wires were reported, operators have used these results to support continued operation. Several operators have reported utilising repeat inspections, at varying time intervals, which identified either consistent results or indicated an increasing number of unloaded wires within the tensile armour wire structure prompting proactive replacement of the risers. Operators who subsequently undertook dissection of the recovered risers to better understand the root cause of the failures have reported significant discrepancies between the results reported from the inspection and the condition found during dissection. There are several cases reported to the JIP where although unloaded (broken) wires were reported based on one off or repeat inspections, none were identified during dissection. Conversely, two operators have reported a significantly larger number of broken tensile wires during dissection than were reported as unloaded during repeated inspections prior to recovery.
Guidance Note
In order to identify the presence of non-loadbearing armour wires the residual stresses in the armours need to be confirmed. This requires changing the load in the riser which can require production to be temporarily shut down. The inspection tool is sensitive to the location of deployment, as such if repeat inspections require to be completed, then the riser should be marked to indicate where the inspection tool was attached, or provision should be made to leave the clamping ring (used to attach the inspection tool to the riser) in situ to ensure repeatability of inspections and minimise the need for future recalibration. With several operators reporting inconsistencies between the reported condition from inspection and that confirmed via dissection, and noting that the vendor no longer identifies this tool as a means of identifying wire breaks, consideration should be given to utilising additional monitoring or inspection techniques to validate the condition of the tensile armour wire structure.

Table B.35 Technology Review – Microwave Inspection

Inspection / Monitoring / Technology Name	Microwave Inspection
Technology Readiness Level (TRL) (Range 1 to 7)	5
Take-Up (Range 1 to 5)	1 (not yet deployed as field qualified technology)
Industry (JIP) Feedback (Range 1 to 5)	N/A (not yet deployed as field qualified technology)
Summary	
Microwave inspection technology has been developed for assessing outer armour condition (both surface defects and disorganisation).	
Benefits	**Limitations**
• Benefits over alternative technologies such as radiography as a result of reduced safety threats relating to the inspection source. • Easier interpretation of outer armour wire disorganisation compared to techniques which visually scan double wall with multiple overlaid armour signatures.	• Currently only suitable to topside applications where armour wire disorganisation is a threat. • Only allows visualisation of the outermost armour layer surface, unless disorganisation is so significant that the inner armour layer is additionally "exposed".
Procedure	
The scanner is deployed around the flexible pipe and the full circumference scanned for a specific axial length.	
Industry Practice	
Where armour wire disorganisation is the focus of the inspection, the axial position of the scan would be based on the section that is believed to be at highest threat of disorganisation and / or using previous benchmark inspection results. By performing the inspection over a wide bandwidth, the depth through the pipe and the extent of any defects may be verified. If there is significant disorganisation of the outer armour layers, the inner armour positions (and any disorganisation of them) should be visible.	
Guidance Note	
The technology has not yet been deployed as a field qualified solution. Whilst the current technology is focussed on topsides deployment, there has been a limited amount of in-water testing, however, the technology could be developed for subsea deployment.	

Table B.36 Technology Review – Radiography

Inspection / Monitoring / Technology Name	Radiography
Technology Readiness Level (TRL) (Range 1 to 7)	7 Topsides 5 Subsea
Take-Up (Range 1 to 5)	2
Industry (JIP) Feedback (Range 1 to 5)	4 Topsides 2 Subsea
Summary	
This method provides local integrity monitoring checks and is generally applied externally to an on-line system using a double wall shot technique. Single wall shot techniques, requiring access to the bore with corresponding operational limitations, can also be deployed and may allow for images to be taken through bend stiffeners or smaller ancillary equipment.	
Benefits	**Limitations**
• Provides confirmation of integrity status for each metallic layer in the flexible pipe. • Does not rely on the presence of a couplant to obtain images.	• Bore fluid composition can significantly affect the clarity of results. • Long exposure times may be required to achieve an image. • Images are subject to interpretation, requires skilled reviewer. • Water is an effective barrier to the radioactive sources used during inspection, therefore seawater between the source and the flexible or flooding of the annulus can significantly affect the quality of the image obtained.
Procedure	
Several radioactive sources are available however $Iridium^{192}$, $Selenium^{75}$ and X-rays are the most commonly used within industry. Several methods exist for obtaining an image from the radioactive source after the radiation has passed through the flexible pipe/end fitting.	
Industry Practice	
To date, the use of radiographic inspection technologies has been limited to assets where there are known risks associated with armour wire failure. Historically a single use film was utilised however this required recovery and replacement after each exposure and as	

such resulted in lengthy inspections particularly when repeat scans were required due to poor image quality. Similarly, advancement in digital radiography has seen the use of reusable plates which once exposed can be scanned to recover the image before being re-used. Initially these digital plates also required to be recovered to be scanned however tooling has been developed to allow image scanning and recovery in-situ. This allows images to be taken and converted digitally for transmission to the control operator where they can be reviewed and either stored or additional images taken as required without the need to recover the inspection tooling.

Single wall shot and double wall shot radiography has been in use by operators to determine the integrity of their flexible pipes, albeit infrequently, since prior to 2002. As outlined above, improvements in the image retrieval process has increased the efficiency of radiographic inspection, however, the quality of retrieved images has been variable especially in subsea exposures. It has been identified that the bore fluid, especially multiphase production, can significantly affect the quality of the images that are obtained. A level of post processing and enhancement of the images is often required for the image to be readable however the clarity of the resultant image often lacks definition.

Recent developments in the use of x-rays or gamma sources of specifically selected power outputs combined with digital imaging plates and post processing of images has demonstrated that high quality images can be obtained above water whilst testing continues to develop more robust subsea inspection equipment.

Guidance Note

As with other inspection techniques such as eddy current and ultrasonic inspections, one of the key reasons for the infrequent use of the technology has been the historic inability to inspect inaccessible key locations. Based on more recent experience, one operator reports using single wall shot imaging through the bend stiffener to capture the condition of the armour wires. The images obtained were of sufficient quality to identify broken armour wires within the bend stiffener region, however signal interference from the bend stiffener polymer material resulted in fine details, such as cracks, being more challenging to identify with confidence.

A further challenge has centred on the limited area each image covers which significantly impacts the time it takes to complete an inspection. Work is ongoing to further improve the reliability and speed with which inspections can be carried out, much of which relies on improvements to digital image recovery solutions, 3rd generation imaging and software units are expected to be available in the near term.

The strength of the radioactive source currently dictates the exposure time that is required to obtain an image, however there is some experience to suggest that the use of a lower strength source with longer exposure times may produce higher quality images in some situations.

Table B.37 Technology Review – Acoustic Emission (Tensile Armour Monitoring)

Inspection / Monitoring / Technology Name	**Acoustic Emission (tensile armour monitoring)**
Technology Readiness Level (TRL) (Range 1 to 7)	7
Take-Up (Range 1 to 5)	1
Industry (JIP) Feedback (Range 1 to 5)	4
Summary	
A continuous monitoring technique that utilises acoustic emissions, with some vendors using additional accelerometers, to identify failure of the tensile armour wires. The qualified detection range is in the region between 10 m – 20 m from the sensor depending on the supplier, however additional sensors can be utilised if detection range requires to be extended.	
Benefits	**Limitations**
• Detection of progressive armour wire failure.	• Only detects a failure as it occurs, cannot retrospectively identify a failure. • Only detects failures within fixed range/distance of deployed sensors. • Requires an initial period of monitoring to calibrate the system to establish event detection criteria.
Procedure	
Acoustic sensors and optional accelerometers, mounted on the end fittings and outer sheath of risers, detect ambient background noise levels and monitor for specific transient acoustic signals or energy emissions originating from the riser that can be attributed to the failure (fracture) of an armour wire. Monitoring of emissions is typically carried out within frequency ranges of 20 kHz to 1.2 MHz which is above the audible range (up to 20 kHz).	
Industry Practice	
Several systems have been developed and completed full scale blind testing onshore. However, there are relatively low numbers of offshore installations to date. The limited industry take-up can likely be attributed to the rarity [see Section 4.0 for failure statistics] of full scale armour wire failures (e.g. breach and failure of the riser) within the industry. To date, the installation of these monitoring technologies has been limited to assets where there are known risks associated with armour wire failure. This includes the successful identification of progressive armour wire failures of in-service risers using an acoustic and accelerometer based tool, prompting the proactive recovery and confirmation of wire breaks through subsequent dissection.	

Guidance Note
Acoustic emission / accelerometer based monitoring solutions rely on having sufficient calibration information available to allow them to differentiate between 'normal' background responses and those relating to a failure event. As with all such systems, calibration across a wide range of situations should be conducted to confirm what should be expected. As the duration of exposure increases, so the level of confidence in the system will increase. The challenge, however, is that when a new situation is encountered there is insufficient 'normal' information to allow for a comparison to be made. To provide additional confidence in the acoustic result, additional elements, such as torsional, lateral or axial accelerations of the riser, can be monitored in parallel. It is known that at least one vendor utilising this combined monitoring approach has successfully identified in-service tensile armour wire failures. It is recommended that whilst monitoring tools such as this can be an effective indicator of an incident occurring, secondary validation by another means should be completed to confirm the result. As it is recognised that retrofit monitoring systems are not capable of identifying failures that occurred prior to the system installation, consideration should be given to ascertaining a baseline of the armour wire condition through alternative inspection techniques.

Table B.38 Technology Review – Acoustic Emission (Carcass Monitoring)

Inspection / Monitoring / Technology Name	Acoustic Emission (carcass monitoring)
Technology Readiness Level (TRL) (Range 1 to 7)	6
Take-Up (Range 1 to 5)	1
Industry (JIP) Feedback (Range 1 to 5)	2
Summary	
A continuous monitoring technique that utilises acoustic emissions to detect mechanical failure of the internal carcass of flexible risers.	
Benefits	**Limitations**
• Early detection of internal carcass failure (unravelling / pull out).	• Only detects a defect that grows during monitoring.
Procedure	
Acoustic sensors, mounted on the end fittings of risers, detect ambient background noise levels, and monitor for specific transient acoustic signals originating from the riser that can be attributed to the failure (unravelling / pull out) of the carcass. Monitoring using acoustic emissions is typically carried out within frequency ranges of 20 kHz to 1.2 MHz which is above the audible range (up to 20 kHz).	
Industry Practice	
Limited application in practice to date with no additional experience reported since the last JIP revision (2017). One operator installed the system to several risers to monitor the carcass condition. An acoustic signal was detected during start-up of the production system which was assessed as relating to the failure of the riser carcass. Subsequent recovery and dissection of the flexible showed this to be a false alarm.	
Guidance Note	
Acoustic monitoring solutions rely on having sufficient calibration information available to allow them to differentiate between 'normal' background emissions and those relating to a failure event. As with all such systems, calibration across a wide range of situations should be conducted in order to confirm what should be expected. As the duration of exposure and number of deployments increases, so the level of confidence in the system may increase. The challenge, however, is that when a new situation is encountered there is insufficient 'normal' information to allow for a reliable comparison to be made. As such, it is recommended that whilst monitoring tools such as this can be an effective indicator, secondary validation by another means should be completed in order to confirm the result.	

Table B.39 Technology Review – Internal Inspection

Inspection / Monitoring / Technology Name	Internal Inspection (visual)	Internal Inspection (LASER)
Technology Readiness Level (TRL) (Range 1 to 7)	7	6
Take-Up (Range 1 to 5)	2	2
Industry (JIP) Feedback (Range 1 to 5)	4	4
Summary		
Internal inspection is normally only deployed on a reactive / as-required basis due to the requirements of cleaning and breaking of containment. Internal inspection of recovered flexibles is more routine. The inspection may be performed using traditional camera (visual) or with specialist scanning tools e.g. LASER.		
Benefits	**Limitations**	
• Confirms internal condition of the flexible bore. • Can be used to monitor for carcass damage, extension or pull-out.	• Requires access to the bore and competent isolations of hazardous fluids. • Some tools may have limited ability to transition past a hogbend or traverse horizontal sections. • Inspection may be limited by bore deposits and / or require significant flushing/cleaning prior to inspection. • Normally requires production to be stopped in order to allow inspection.	
Procedure		
Once appropriate preliminary flushing and cleaning treatments have been applied to the flexible and access is obtained to the bore a camera (or alternative scanning tool) is passed down the inside of the flexible to record or relay live images of the flexible pipe internal condition. Following completion of inspection activities pipework reinstatement and appropriate integrity testing is required which has the potential to result in significant disruption to operations.		
Industry Practice		
Internal inspection is not routinely applied and tends to be utilised only where an anomaly / damage has been identified or suspected through other means. Multiple vendors supply internal inspection tools which vary in complexity from cameras tethered to control cables which are lowered directly into a flexible riser, to tethered crawlers and autonomous carriages. Specific tooling has also been developed to inspect flexible pipes that are stored on reels either post recovery or pre-deployment. Internal inspection has successfully been used to identify internal collapse of the pressure sheath/carcass (typically		

where multilayer pressure sheaths have been employed) and as a monitoring tool to identify carcass tear-out / extension or end fitting pull out of PVDF pressure sheaths. Inspection tools have also been deployed to inspect topside jumpers to verify where smooth bore collapse has occurred.
Guidance Note
As the inspection of the bore is inherently invasive and likely to result in significant operational disruption, operational internal inspection is not routinely carried out unless there are specific threats to inspect for. Historically internal inspection has been limited to cases where there is suspected internal damage to the pipe, such as leakage from the end fittings as a result of carcass tear out / extension or pressure sheath movement (witnessed through changes in the pitch of the carcass), or to detect collapse of the internal pressure sheath and/or the carcass.

Table B.40 Technology Review – Flexible ILI

Inspection / Monitoring / Technology Name	Flexible ILI
Technology Readiness Level (TRL) (Range 1 to 7)	7
Take-Up (Range 1 to 5)	2
Industry (JIP) Feedback (Range 1 to 5)	3
Summary	
A technique has been developed to analyse the data recovered from UT intelligent pigging of flexible pipe inspections. The data can be used to identify carcass defects including, stretch, tear out and collapse / deformation of the carcass as well as damage to the isolation ring between the carcass and the end fitting vault.	
Benefits	**Limitations**
• Utilises results obtained from standard UT inspection technology. • Can identify carcass position in the end fitting (pull out / carcass slip identification). • Evaluates the condition of the isolation ring between the inner carcass and the end fitting. • Identifies carcass damage such as tear out and collapse / deformation.	• Cannot identify defects beyond the carcass layer.
Procedure	
Data taken from a UT pig run is processed to investigate the condition of the carcass. Analysis can be completed along the entire flexible length however the section of the riser in the vicinity of the hang-off or other areas of bending are typically of key interest and the focus of the analysis. Processing of the data allows for the position of the carcass relative to the end fitting isolation ring and vault to be identified, providing an indication of whether carcass movement has occurred. The data may also used to identify damage to the end fitting ring or the presence of deformities of the carcass (such as tears or collapse). Analysis of periodic inspection results can be used to identify trends in progressive carcass extension / compression, and potentially, through comparison with the design documentation, to identify if the carcass is fully extended (indicating an increased risk of carcass tear out).	
Industry Practice	
To date there has been limited industry uptake to specifically inspect for carcass condition, however as many operators pass UT pigs through flexible pipe to facilitate the inspection of rigid subsea pipelines, the potential exists to utilise the resultant data to check for carcass defects in addition to validating the rigid pipework condition.	

Guidance Note
The inspection technology has been shown to be effective for specific inspection of carcass defects i.e. extension / pull-out. Some vendors have experimented with different in line inspection techniques in an attempt to provide inspection results for additional layers in the pipe. To date, inspection of anything beyond the inner most layer (carcass or smooth bore tube where fitted) has not been achieved with any degree of confidence or clarity.

Table B.41 Technology Review – Flexible Dissection

Inspection / Monitoring / Technology Name	Flexible Dissection
Technology Readiness Level (TRL) (Range 1 to 7)	7
Take-Up (Range 1 to 5)	4 (failure root cause assessments) 3 (life extension assessments)
Industry (JIP) Feedback (Range 1 to 5)	5
Summary	
Following end of life or failure of a flexible, the pipe, or sections of the pipe, can be recovered and taken onshore to undergo forensic dissection and analysis to determine the cause of failure or to confirm the accumulated damage that the pipe has experienced. The results of the dissection can also be used as justification for continued service of similar flexibles or as a tool to mitigate risks for other operating pipes. In addition, manufacturers routinely perform detailed dissection during qualification and / or type approval programs.	
Benefits	**Limitations**
• Can assist with root cause of failure identification. • Can help to justify continued operation of similar pipes. • Validates pipe design following operations and supports next generation designs.	• Destructive testing technique. • Identification of most critically loaded / damaged sections for further testing and revalidation can be challenging. • Relatively time consuming to complete dissection and analysis.
Procedure	
The detailed procedure for dissection is dependent on the pipe design and also the purpose of the investigation. In general, however, once the flexible has been recovered the pipe is methodically deconstructed layer-by-layer. The section being dissected is marked up to indicate the position relative to the end-fitting (or some other reference point) and circumferentially to match the installed orientation. A visual record is made to document each stage of the process with specific attention given to areas of damage, wire disassociation, unlocking, fractures etc. Measurements are taken to confirm the diameter and ovality of each layer, with the pitch length and the dimensions of any gaps in the armours also recorded. Samples taken from any of the flexible layers are logged and can be subjected to further testing / analysis depending on the focus of the investigation. Ancillary equipment such as buoyancy modules and bend stiffeners etc. can be dissected in a similar manner with samples provided for further analysis.	
Industry Practice	
This procedure is widely employed by the industry to assist with mode of failure identification and to assess failure probability of pipes that are still installed which have similar designs and operating conditions. Dissection of non-	

failed pipes have also been undertaken to justify the continued operation of equivalent pipe designs, or to justify re-use of equivalent pipe from the same batch. This also has the advantage of providing empirical data which can be used to re-baseline design assumptions and improve the functionality / design of future pipes. Typically, detailed forensic dissection of an entire cross section is limited to approximately 10 m per week for a standard 10-inch pipe, however this will vary based on pipe design and does not include subsequent laboratory analysis of extracted samples.

Historically, riser dissections were completed by the manufacturers, however in recent years independent third-party test centres have also developed the capability to complete dissection and have been engaged by operators to complete dissection works.

It is recommended as good practice that in cases of unexpected failure or cases with the potential for high impact / consequence the flexible pipe manufacturer is consulted to ensure lessons are learned.

Guidance Note

It is important to define (prior to recovery), the purpose of the investigation and the specific areas of interest for the dissection. This will ensure that the area of interest is not damaged during recovery and that sufficient segments / lengths of the pipe are recovered to complete a meaningful assessment. **Preservation between failure, recovery, and dissection is of critical importance, in order to ensure dissection observations can be directly linked to the operational phase of the pipe, and not post recovery degradation**. In the past, some dissections have included additional inspection / monitoring techniques. The use of one technique, or the order in which the techniques are applied, can preclude the use of others. As such, it is recommended that the entire dissection programme is defined in full prior to commencing dissection activities.

In the case of failure analysis, consideration should be given to providing the vendor completing the dissection with as much precursory information in the lead up to the incident / failure as possible as this may help to differentiate between causal and contributory factors.

The chain of custody and the management of the recovered flexible through this chain is of significant importance to ensure that additional external damage or excessive bending etc. is not encountered during the recovery process. Any incidents occurring during the recovery process should be recorded and shared to allow the dissection to take account of these events.

Appendix C Guidance on Use of JIP Databases

C.1 Guidance on Use of JIP Databases

A version of the finalised Damage / Failure database from this JIP, which is aligned with the final version of this report, shall be de-sensitised upon completion of the JIP and shared for use with the JIP members only. The database will not available outside of the JIP membership.

This Appendix provides basic guidance on the JIP Damage / Failure databases.

The database includes a series of parameters for each damage / failure incident event, as per the matrix of experience summarised in Table 4.2. It is important to note that not all parameters are completed for each incident as the data is based on operator-supplied information. In addition, for some of the historical incidents whilst there is confidence in the occurrence of such incidents, relevant details are limited.

As described in Section 4.2, users of the database should be aware of the limitations, specifically that each flexible pipe system is likely to have specific threats which should be assessed, rather than relying solely on historical industry trends.

Appendix D Alternative Damage & Failure Incident Rates

D.1 Alternative Damage & Failure Incident Rates

D.1.1 General

During the course of the JIP, members requested that alternative damage and failure incident rates be calculated as a sensitivity to those presented in Section 4.3.3. These alternative rates omit damage and failure incidents not directly linked to the flexible pipe system itself, as discussed in the following sub-section.

D.1.2 Inclusions / Exclusions

The alternative damage and failure incident rates include all incidents attributed to the flexible pipe system (i.e. the flexible pipe including end fittings and associated ancillary equipment). However, incidents are excluded from the dataset where the damage / failure was attributed to the following:

- Mishandling during installation / handling.
- Maloperation (e.g. the flexible pipe is operated outside of its design limits).
- 3rd party interaction (i.e. dropped objects, trawl board impact or dragging).
- Inappropriate pigging.
- Abnormal accidental / extreme weather events not accounted for in design.
- Commissioning errors (e.g. vent system either not installed / installed incorrectly).

Table D.1 below shows the updated number of incidents considered in the alternative failure rates with these exclusions applied. Numbers in brackets show the reduction in incidents from the original dataset (as presented in Table 4.12). In total, 85 cases are excluded (52 relating to Risers, 33 relating to Flowlines & Jumpers). Of these 68 have dates assigned and are therefore excluded from the alternative damage and failure incident rates (42 relating to Risers, 26 relating to Flowlines & Jumpers).

D.1.3 Alternative Damage & Failure Incident Rates

Figure D.1 and Figure D.2 presents the timeline history of event numbers for Risers and Flowlines & Jumpers respectively. Table D.2 presents the corresponding incident rates over time, as a comparison to Table 4.14.

Table D.1 Damage & Failure Experience and Timeline Datasets – Sensitivity Dataset

Status	**Riser**			**Flowline & Jumper**		
	Number of Incidents	**Incidents with Dates**	**% Incidents with Dates**	**Number of Incidents**	**Incidents with Dates**	**% Incidents with Dates**
Damaged	299 *(-42)*	250 *(-34)*	84%	9 *(-21)*	8 *(-17)*	89%
Failed-Leak	63 *(-8)*	54 *(-6)*	86%	67 *(-9)*	62 *(-6)*	93%
Failed-Rupture	23 *(-2)*	23 *(-2)*	100%	6 *(-3)*	6 *(-3)*	100%
Total	**385 *(-52)***	**327 *(-42)***	**85%**	**82 *(-33)***	**76 *(-26)***	**93%**

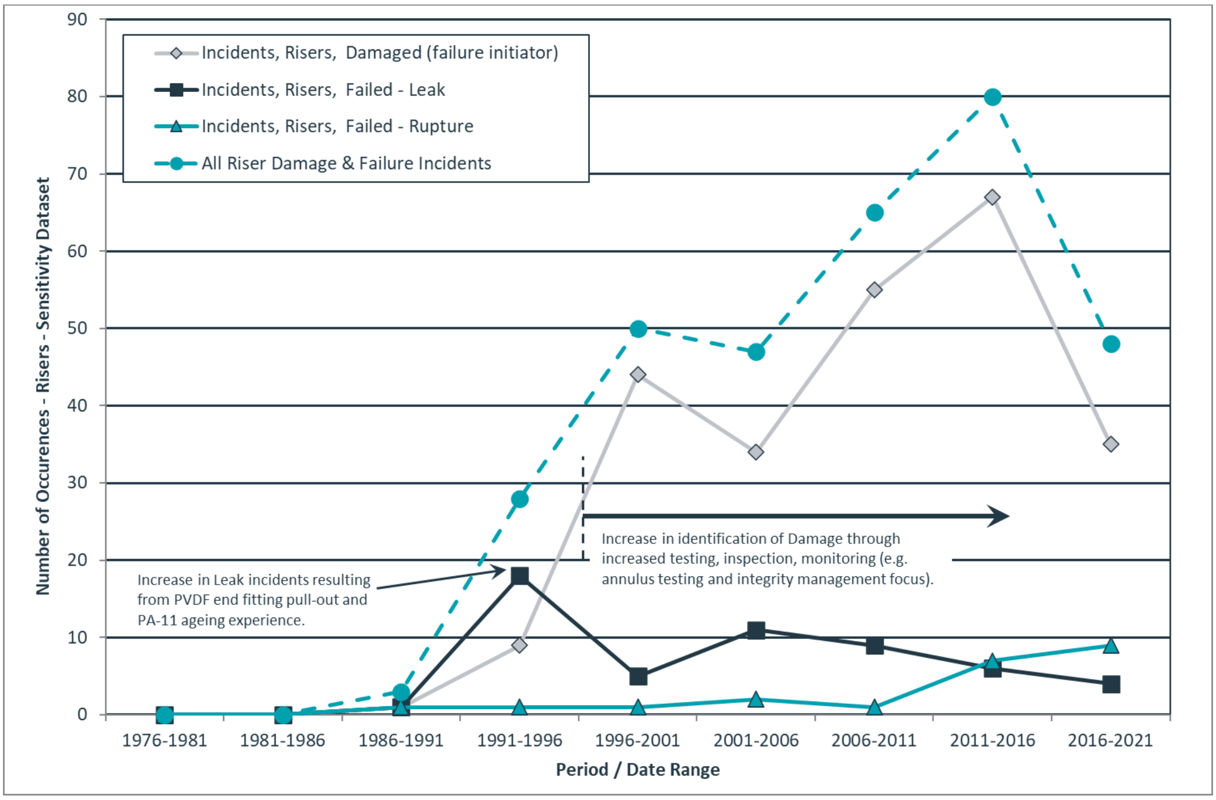


Figure D.1 Damage & Failure Timeline – Risers – Sensitivity Dataset

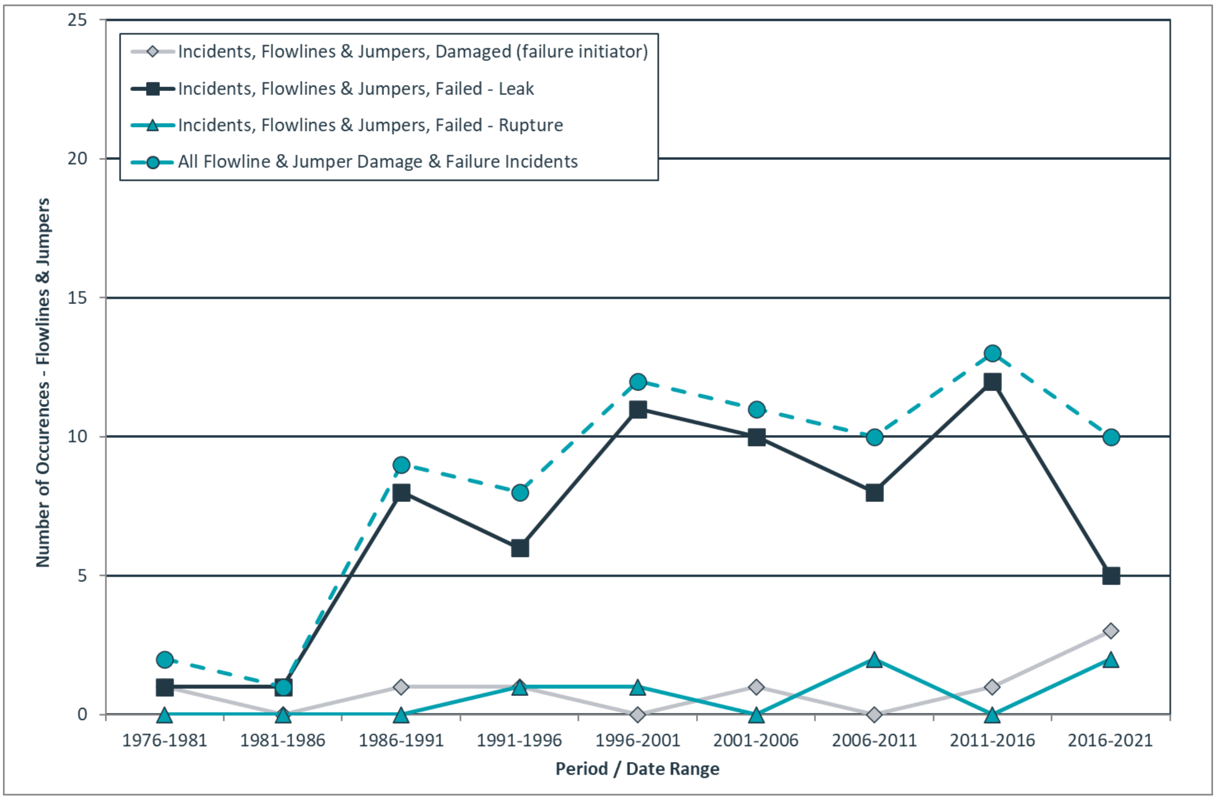
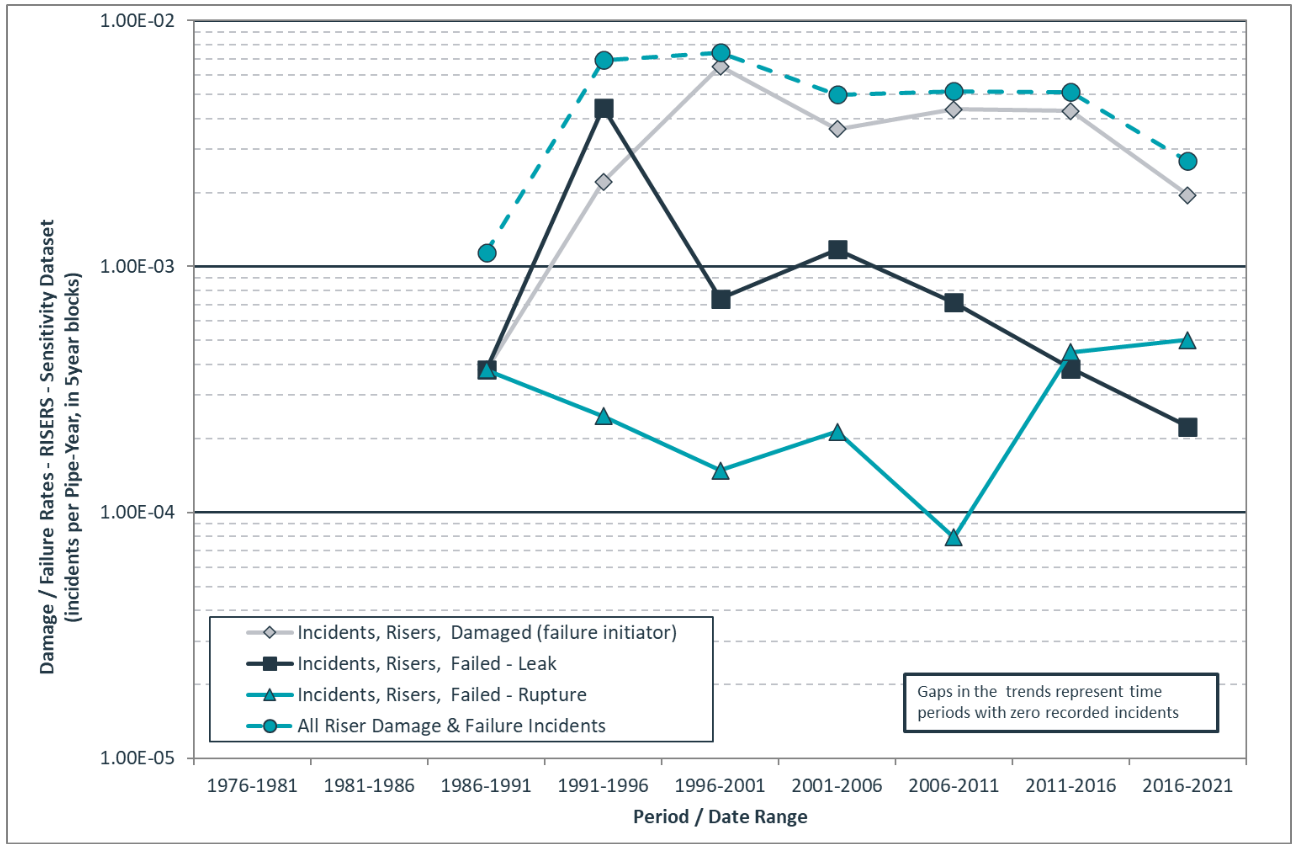
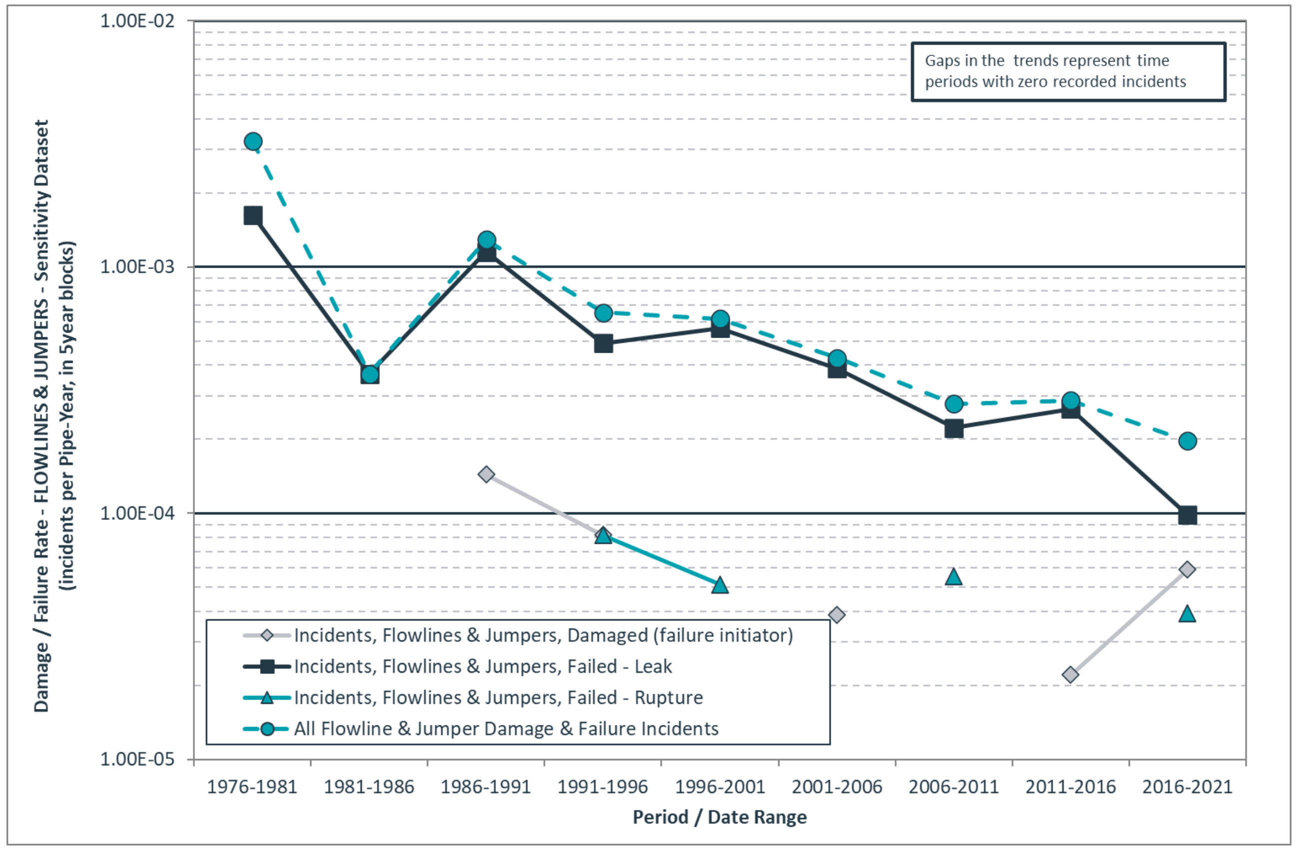


Figure D.2 Damage & Failure Timeline – Flowlines & Jumpers - Sensitivity Dataset

Table D.2 Damage & Failure Incident Rates (Incidents per Pipe-Year) – Sensitivity Dataset

Period	Damage / Failure Rate (incidents per pipe-year)							
	Risers				Flowlines & Jumpers			
	Damaged	Failed - Leak	Failed - Rupture	ALL COMBINED	Damaged	Failed - Leak	Failed - Rupture	ALL COMBINED
1976 – 1981					1.63E-03	1.63E-03		3.25E-03
1981 – 1986						3.68E-04		3.68E-04
1986 – 1991	3.80E-04	3.80E-04	3.80E-04	1.14E-03	1.44E-04	1.15E-03		1.29E-03
1991 – 1996	2.22E-03	4.43E-03	2.46E-04	6.89E-03	8.16E-05	4.90E-04	8.16E-05	6.53E-04
1996 – 2001	6.52E-03	7.40E-04	1.48E-04	7.40E-03		5.65E-04	5.14E-05	6.17E-04
2001 – 2006	3.62E-03	1.17E-03	2.13E-04	5.01E-03	3.88E-05	3.88E-04		4.27E-04
2006 – 2011	4.36E-03	7.13E-04	7.92E-05	5.15E-03		2.22E-04	5.56E-05	2.78E-04
2011 – 2016	4.29E-03	3.84E-04	4.48E-04	5.12E-03	2.21E-05	2.65E-04		2.87E-04
2016 – 2021	1.95E-03	2.23E-04	5.02E-04	2.68E-03	5.91E-05	9.84E-05	3.94E-05	1.97E-04
1976 – 2021	**3.49E-03**	**7.69E-04**	**3.13E-04**	**4.57E-03**	**4.00E-05**	**3.10E-04**	**3.00E-05**	**3.80E-04**





Appendix E Flexible Pipe Damage & Failure Reporting Template

E.1 Flexible Pipe Damage & Failure Reporting Template

E.1.1 Objective

The objective is to present a standardised template for reporting damage and failure experience, which is consistent with the reporting standard for the Sureflex JIP.

E.1.2 Reporting Template Details

The reporting template is available in a spreadsheet format and has been shared with all members of the JIP as part of the project closeout. The intent of this appendix is to present the reporting template in "hard copy", along with supporting information required to populate a report following the identification of any reportable degradation.

The following pages include:

- 1-page form, presented on the following page of this report,
- The options for the "controlled fields" in the reporting template, Table E.1 & Table E.2.

The controlled fields for the "Damage / Failure Cause" parameter are summarised in Table E.1. More detailed descriptions of the causes are included in Appendix A (Table A.1) of this report for information.

Parameters within the reporting template are either defined as *Essential* or *Desirable*. Gathering of the additional information in the *Desirable* category should allow further sharing across the industry with regards to lessons learned and add value by identifying additional common failure trends for pipes in common applications.

E.1.3 Recommended Approach to Use

One of the most significant challenges of keeping damage and failure statistics up to date relates to the fact that data is normally gathered periodically as opposed to at the time of the damage / failure. This relies on the corporate knowledge / memory of the organisation for retrospective reporting, which can degrade over the (sometimes lengthy) reporting intervals. As such, **it is strongly recommended that reports are populated at the time of identification of damage / failure**, and updated following any investigative close-out.

Reporting can either be performed using a hand written copy of the template on the following page, or the spreadsheet version can be supplied by email upon request (contact details below, Section E.1.4).

Once populated, reports can either be sent in for secure storage centrally alongside the existing JIP database. Alternatively, reporting organisations may elect to store draft reports for submission at the time of a future update of the damage and failure databases. **All collated data will be desensitised using the same approach as utilised in this JIP**.

E.1.4 Contact Details for Questions and / or Report Submissions

For any questions or queries relating to the reporting template, please email sureflex@woodplc.com. This central email can also be used to request the spreadsheet version of the reporting template or to discuss the reporting of a specific incident.

Sureflex Joint Industry Project

Flexible Pipe Damage and Failure Reporting Template

Classification of Data	
Essential	Information denoted as Essential is the minimum requirement in order to have data in the database which is "usable" to some extent.
Desirable	It is **strongly desirable** that this data is reported to provide added value to the available shared damage and failure statistics.
*	"*" denotes data required to avoid duplication in the database or to seek further clarity. Data will not be shared. All database data will be desensitised.

Category	Data Required	Classification of Data	Input Data
Who is Reporting the Incident?	Name	Essential*	
	Organisation	Essential*	
	Contact Phone Number(s)	Essential*	
	Contact Email Address	Essential*	
	Date of Completion of this Report	Desirable	
Incident Details	Operator Name	Essential*	
	Field Location / Platform Name	Essential*	
	Pipe Ident. / Code / Ref. No. (if applicable)	Desirable*	
	Facility / Platform Type (if applicable)	Essential	Please Select
	Status / Type of Incident	Essential	Please Select
	Number of Identical Pipes Covered by this Report	Essential	
	Damage / Failure Cause - Refer to Definitions Listing	Essential	Please Select
	Location / Depth of Incident Location	Essential	
	How was Damage / Failure Discovered / Suspected?	Essential	
	Was any Repair Activity considered / effected	Desirable	
	Was any Repair Activity successful (if applicable)	Desirable	
	Were any other mitigating actions implemented, either on this pipe or related pipes?	Desirable	
Timeline	Installation Date (either year or dd/mm/yyyy if known)	Essential	
	Date of First Use (either year or dd/mm/yyyy if known)	Desirable	
	Original Design Life (years)	Essential	
	Current Design Life (years), if different	Desirable	
	Is the incident date known?	Essential	Please Select
	Date of Incident, or detection date if actual unknown (either year or dd/mm/yyyy if known)	Essential	
	Phase of Pipe Life Cycle during which Incident was identified	Essential	Please Select
	Recovery / Abandonment Date (either year or dd/mm/yyyy if known)	Desirable	
Flexible Pipe Design Details / Configuration	Pipe Application / Type	Essential	Please Select
	Riser Configuration (if applicable)	Desirable	Please Select
	Rough Bore / Smooth Bore Pipe	Desirable	Please Select
	Internal Pressure Sheath Material	Essential	Please Select
	Number of Internal Pressure Sheath Layers	Essential	Please Select
	Independent Pressure Armour or 55deg Pipe	Desirable	Please Select
	Sweet / Sour Service Armours	Desirable	Please Select
	Insulation Layer	Desirable	Please Select
	External Sheath Material	Desirable	Please Select
	Number of External Sheath Layers	Desirable	Please Select
	Manufacturer	Desirable	
Design & Operating Data	Product Use	Essential	Please Select
	Pipe Inner Diameter (mm)	Essential	
	Flexible Pipe Length (m)	Desirable	
	Temperature - Design (degC)	Essential	
	Temperature - Normal Operating / typical (degC)	Desirable	
	Temperature - Maximum Operating (degC)	Desirable	
	Pressure - Design (barg)	Essential	
	Pressure - Normal Operating / typical (barg)	Desirable	
	Pressure - Maximum Operating (barg)	Desirable	
	Field Water Depth (m) if applicable	Essential	
	Wave Environment	Desirable	Please Select
	Current Environment	Desirable	Please Select
Other Notes Please add any other notes / information relating to incident e.g prior use / re-use, root causes and contributory factors, investigation findings, other reference material etc			

Table E.1 Controlled Fields in Reporting Template (1)

Facility / Platform Type (if applicable)	Damage / Failure Cause - Refer to Definitions Listing
Please Select	Please Select
n/a	Line Recovered Proactively - No significant damage / defect identified
FPSO - internal turret	Carcass Failure - Erosion
FPSO - external turret	Carcass Failure - Fatigue
FPSO - disconnectable turret	Carcass Failure - Multilayer PVDF Collapse
Fixed Platform - within caisson / tube	Carcass Failure - Tearing / Pullout
Fixed Platform - externally mounted	Internal Damage - Pigging
Semi-sub - subsea hangoff	Internal Pressure Sheath - Ageing
Semi-sub - above water hangoff	Internal Pressure Sheath - End Fitting Pull-out
TLP - subsea hangoff	Internal Pressure Sheath - Fatigue / Fracture / Microleaks
TLP - above water hangoff	Internal Pressure Sheath - Smooth Bore Liner Collapse
Compliant Tower	Pressure Armour Wire Fracture - in / close to end fitting
Drilling Rig	Pressure Armour Wire Fracture - in main pipe section
Jackup	Tensile Armour Wire Fracture - in / close to end fitting
SPAR	Tensile Armour Wire Fracture - in main pipe section
Barge	Tensile Armours - Birdcaging
Other (please state in notes)	Tensile Armours - Lateral Buckling
	Corrosion of Armours - Major / Catastrophic - add notes on mechanism if known
Status / Type of Incident	Corrosion of Armours - Moderate - add notes on mechanism if known
Please Select	Annulus Flooding - Cause Unknown
Operating (minor defect / damage)	Annulus Flooding - Defective Annulus Vent System
Damaged (failure initiator)	Annulus Flooding - Outer Sheath Damage - Ageing / Fracture
Shut-down (integrity concern)	Annulus Flooding - Outer Sheath Damage - Mechanical / Impact / Wear
Failed - Leak	Annulus Flooding - Permeated Liquids
Failed - Rupture	Outer Sheath Damage - Annulus NOT flooded - Ageing / Fracture
Failed - Connected System Failure	Outer Sheath Damage - Annulus NOT flooded - Mechanical / Impact / Wear
Installed (not operating)	End Fitting Leak / Failure
Recovered-End of Design Life	Ancillary Equipment - Bend Restrictor
Recovered-Before Design Life	Ancillary Equipment - Bend Stiffener - Connection / Interface
	Ancillary Equipment - Bend Stiffener - 2 part failure
	Ancillary Equipment - Bend Stiffener - other
	Ancillary Equipment - Buoyancy Modules
	Ancillary Equipment - CP system
	Ancillary Equipment - Hang-off Failure
	Ancillary Equipment - Hold-down Failure (tethers / clamps / connections)
	Ancillary Equipment - Mid Water Arch
	Ancillary Equipment - Vent System Anomalies / Blockage
	Ancillary Equipment - Other (please state which type)
	Global pipe defect - Dropped Object
	Global pipe defect - Excess Tension
	Global pipe defect - Mooring Failure / Excess Offset
	Global pipe defect - Excess Torsion
	Global pipe defect - Flow Induced Pulsation (FLIP) causing wider system effect
	Global pipe defect - Ovalisation
	Global pipe defect - Overbend / Pressure Armour Unlock
	Global pipe defect - Rough Bore Collapse
	Global pipe defect - Smooth Bore Collapse
	Global pipe defect - Upheaval Buckling
	Global pipe defect - Pipe Blockage (wax/hydrates/other)
	Global pipe defect - Excess Marine Growth
	Other (please state in notes)

Table E.2 Controlled Fields in Reporting Template (2)

Is the incident date known?
Please Select
Yes
No

Phase of Pipe Life Cycle during which Incident Occurs
Please Select
Manufacture
FAT
Handling / Transportation
Installation
Commissioning
Operation
Decommissioning

Pipe Application / Type
Please Select
Riser-Dynamic
Riser-Static
Jumper-Topsides
Jumper-Subsea
Jumper-Subsea (bundled)
Flowline
Other (please state in notes)

Riser Configuration (if applicable)
Please Select
n/a
Free Hanging Catenary
Catenary between facilities
Lazy Wave
Steep Wave
Lazy -S
Steep-S
Pliant/Tethered Wave
Hybrid Tower Jumper
Other (please state in notes)

Rough / Smooth Bore
Please Select
Rough Bore (Carcass)
Smooth Bore (No Carcass)

Internal Pressure Sheath Material
Please Select
Polyamide (PA-11)
Polyamide (PA-12)
Polyethylene (PE)
Crosslinked PE (XLPE)
PVDF-Grade unknown
PVDF-Coflon
PVDF-Gammaflex
PVDF-CoflonXD
Other (please state in notes)

Number of Internal Pressure Sheath Layers
Please Select
Single
Double
Triple

Independent Pressure Armour or 55deg Pipe
Please Select
Press. Arm., Tens. Arm. ~35deg
No Press. Arm., Tens. Arm. ~55deg

Sweet / Sour Service Armours
Please Select
Sweet
Sour

Insulation Layer
Please Select
Yes
No
Unknown

External Sheath Material
Please Select
PA
PE
TPE
Other (please state in notes)

Number of External Sheath Layers
Please Select
Single
Double-Partial Length
Double-Full Length

Product Use
Please Select
Gas Lift
Gas Injection / Disposal
Gas Import / Export (separated)
Oil Import / Export (separated)
Production (multiphase oil)
Production (gas / condensate)
Water Injection
Test
Drill Mud
Cement
Other (please state in notes)

Wave Environment
Please Select
Benign, no impact on fatigue / extreme design
Moderate, some impact on fatigue / extreme design
Severe, significant impact on fatigue / extreme design

Current Environment
Please Select
Benign, no impact on fatigue / extreme design
Moderate, some impact on fatigue / extreme design
Severe, significant impact on fatigue / extreme design