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DIFFERENTIAL BURST PRESSURE OF MARINE PIPELINES AS AN INDEPENDENDT LAYER OF PROTECTION

Sirous F. Yasseri **R.B. Mahani**

ABSTRACT

Offshore pipelines and risers are designed to different codes leading to different reliability targets, and different wall thicknesses. Pipeline design codes also differentiate between areas where people are present and those with no population or less environmentally sensitive. As a result, the offshore section of the pipeline (with “thinner walls”) could be considered to work as a structural fuse during an unforeseen pressure surge; if the pipeline bursts first, then the occupants of platform would be exposed to less risk than if the riser or pipeline in the vicinity of the platform were to fail. This implies that differential burst pressure could act as an Independent Protection Layer (IPL). This paper explores conditions that sections of a pipeline must satisfy in order to be considered as an IPL. A first order reliability method is outlined for determining the required target reliability. The application of this approach is described in a case study.

INTRODUCTION

The prevention of loss of containment due to pipeline overpressure is a major consideration for offshore industry; especially on an installation or in its proximity. In conventional designs, pressure relief devices, such as pressure-relief or -safety valves, are used as the primary means of pressure protection. The use of an instrumented system to protect against overpressure is common place now. However, this instrumented system must meet or exceed the protection provided by the pressure relief devices. These are safety instrumented systems (SIS), since their failure can result in the release of hazardous chemicals and/or the creation of unsafe working conditions. As SISs, they must be designed according to the international standard IEC 61511. The risk typically involved with overpressure protection results in the need for high SIS integrity; therefore, these systems are often called High Integrity Pressure Protection Systems (HIPPS) or High Integrity Protection Shutdowns (HIPS). The use of HIPPS must result in an installation as safe as, or safer than, the conventional design and the HIPPS can only be used when the use of pressure relief devices is *impractical*. The international standard, IEC 61508, “Functional Safety of Electrical / Electronic / Programmable Electronic Safety Related Systems,” establishes a framework for the design of instrumented systems that are used to mitigate safety-related risks.

Systems in place which could control or mitigate an initiating event are known as control or mitigation barriers. Reason (21) conceptualizes such barrier as inherently imperfect as shown in Figure 1. Thus, more barriers there are a better chance of arresting an unfolding event.

Figure 1- Reason’s accident model (21).

Impeding progression of an event by erecting barriers on its path is also known as defence in depth. Defence in depth is the practice of layering defences to provide added protection. Defence in depth increases safety by reducing either the frequency or consequence, or both. The idea is to place multiple barriers between an event and vulnerable targets: More lines of defence (protection layers) could arrest or at least mitigate the effect and more layers mean a better defence/protection system (figure 2).

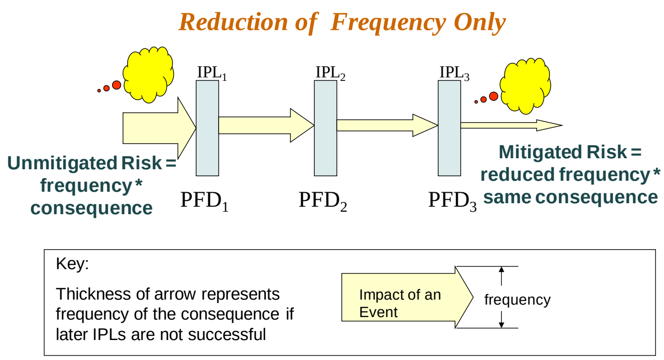

Figure 2 Independent Protestation Layer. Each has its own Probability of Failure on demand (PFD). This Figure shows the mitigation by reduction of frequency only. It is also possible to mitigate the consequences.

Independent Protective Layers (IPL) are devices, systems, or actions that are capable of preventing a scenario from proceeding to an undesired consequence and all these layers are independent from one another so that failure of any one layer will not affect the functioning of the other layers. The layers can be either preventive in nature by avoiding an occurrence of the scenario or mitigating by minimizing the effects of consequences. Examples for preventive independent protective layers are inherently safe design features, physical protection such as relief devices, Safety Instrumented Systems etc. For a pipeline, thicker wall than needed, corrosion coating and controlled buckling are also protection layers. Post release physical protection like fire protection systems, routing, plant and community emergency response etc can be considered as mitigating protective layers. Figure 3 shows the idea of defence in depth.

Layers of protection analysis (LOPA) are used to identify safeguards that meet the independent protection layer (IPL) criteria. While IPLs are extrinsic safety systems, they can be active or passive systems, as long as the following criteria are met:
Specificity: The IPL is capable of detecting and preventing or mitigating the consequences of specified, potentially hazardous event(s), such as a runaway reaction, loss of containment, or an explosion.
Independence: An IPL is independent of all the other protection layers associated with the identified potentially hazardous event. Independence requires that the performance is not affected by the failure of another protection layer or by the conditions that caused another protection layer to fail. Most importantly, the protection layer is independent of the initiating cause.

Dependability: The protection provided by the IPL reduces the identified risk by a known and specified amount.

Examples of IPLs are as follows:
• Standard operating procedures,
• Basic process control systems,
• Alarms with defined operator response,
• Safety instrumented systems (SIS),
• Pressure relief devices,
• Differential wall thickness,
• Fire and gas systems, and
• Corrosion protection.

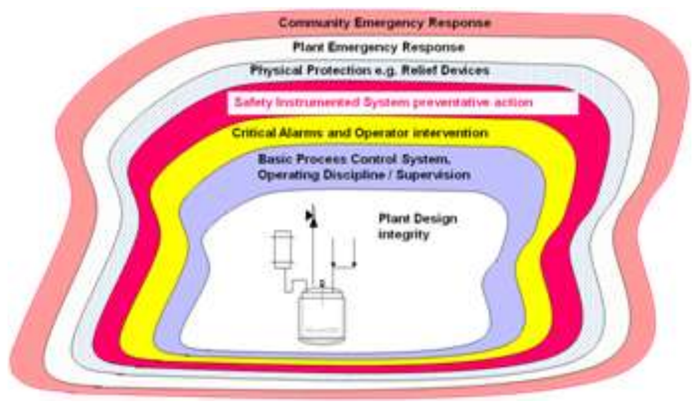

Figure 3-The concept of defence in depth or multi level protection layers (barriers).

For a pipeline threats are uncontrolled pressure excursion, corrosion, external interference, etc., and barriers are relief valves, HIPPS, corrosion protection coatings, surveillance, etc. One can construct a series of barriers to ensure that threats never cause an incident, i.e.

- Barriers that prevent an incident (e.g. coatings on pipelines);
- Barriers that detect a possible incident, before it occurs (e.g. inspection).

NOMENCLATURE

Nomenclature	Description
ESD	Emergency Shutdown
HIPPS	High Integrity Pressure Protection System
HP	High Pressure
ICSS	Integrated Control & Safety System
IL	Integrity Level
IPL	Independent Protection Layer
LOPA	Layer of Protection Analysis
LP	Low Pressure
MCS	Master Control System
MCS	Master Control System
PMV	Production Master Valve

SCM	Subsea Control Module
SCSSV	Surface controlled Subsurface Safety Valve
SIWHP	Shut-in Wellhead Pressure
SSIV	Sub-Surface Isolation Valve
TIV	Tree Isolation Valve
TMEL	Target Mitigated Event Likelihood

DIFFRENTIAL BURST PRESSURE AS AN IPL

Defence in depth is adding redundancy to the safety system and as such redundancy is a key safety concept, Figure 4.

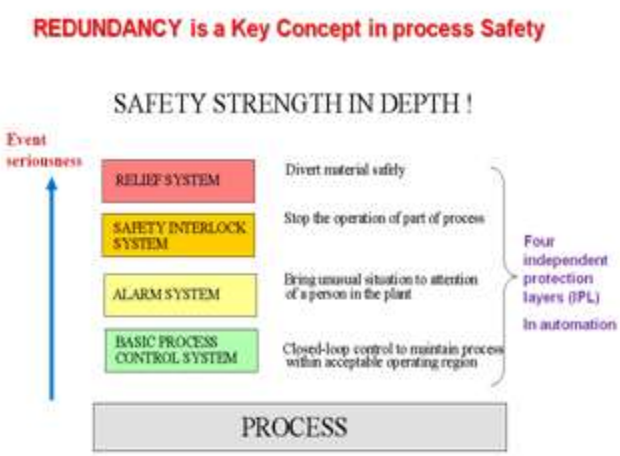

Figure 4 Redundant systems for the process safety

Figure 5 shows the basic element of a design. An installation is designed for certain operating conditions with a certain safety margin. Various control systems are implemented to prevent excursion beyond this limit. Design accidents (as scenarios) are identified to assure life safety. However, there is a limit for each and there is always a possibility of any minor accident to turn into a major one. Hence, it is desirable to reduce accidents where people are present. Fortifying sections of a pipeline close to the installation, in order not to fail first can be considered as one of such IPL.

Pipelines are designed not to burst under maximum operating pressure (MOP) and for this reason the MOP is suitably kept below the burst pressure. This is to protect the pipeline and its surroundings. In sensitive or heavily populated areas as well as in the proximity of installations the difference between MOP and the burst pressure is more, by requiring a thicker wall thickness. This differential treatment of the pipeline segments is an acknowledgement of importance of some part of pipeline surroundings (not the asset) over the rest. The intention is to provide additional protection to the occupant of an offshore platform. However, the codified method only assures that the probability of pipeline failure around the platform is less than the probability of failure for the rest of the pipeline. The implementation of differential treatment is via an importance factor which directly affects the wall thickness. However, such differential treatment can only reduce the probability failure in areas with fortified wall thickness. In the context of defence in depth there is a need to assure that during a surge, the unfortified section fails first and hence acts as an IPL. Ability to maintain consistent reliability levels throughout its life time is a key requirement. Thus, a reliability target must be met throughout the life of the pipeline.

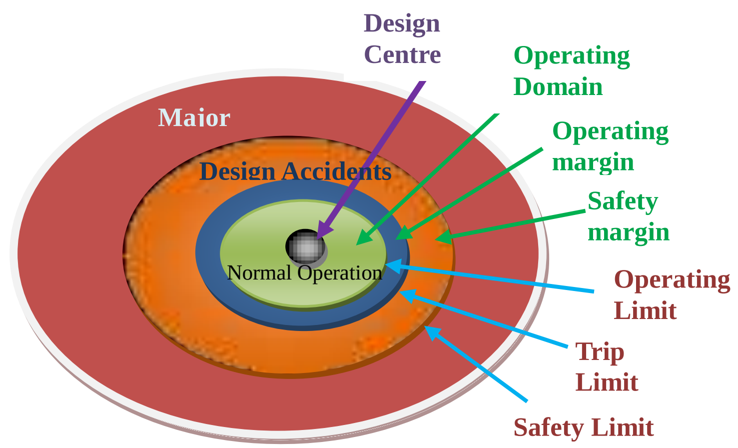

Figure 5 – Conceptualisation of elements of a design showing normal operating region, safety margin (implemented by design accident scenario) and extreme events.

A combination of factors contributes to the pipeline failure. These factors include operational conditions, design parameters, external interferences, internal loads (operating and surge pressures), temperature changes, loss of bedding, material properties & condition, and corrosion pit geometry. It is very difficult to ascertain the precise causes of failure. Even if all this information were available, any attempt to estimate the pipe condition state would involve considerable uncertainty due to large spatial and temporal variability that is inherent in this information.

The pressure surge beyond the burst pressure of the pipeline is the only issue here, as any other parameter of pipelines safety would remain the same for all segments. Since pressure surge will be transmitted from the pipelines to risers and finally to the topside piping with all protection layers on its path. This paper only considers pressure surge as an initiating event and the preferential burst is used as an Independent Layer of Protection (ILP) against this event. To achieve this, part of a pipeline which is close to the platform or the subsea installation is fortified so that it won't burst first. The predominant failure mode of interest is the pipeline burst and uncertainties associated with its prediction.

Internal pressure is not the only load that a pipeline experiences in operation, but accounting for all stresses requires section-to-section investigation. Stresses acting on the pipeline are not uniform on a cross section or uniform along the length of the pipeline. However, all sections of a pipeline designed to a code should have similar margin of safety against such stresses. For the present purposes, support and loading variations along the pipeline are assumed to be identical at each cross section. It is assumed also that the pipeline cross section is in a state of plane strain, (i.e., longitudinal movements or deformations are ignored), and it is at constant and uniform temperature. These assumptions are not realistic when spanning is involved. In addition to the internal and the external pressures, the pipeline is subject, in general, to corrosion, either externally or internally or both. Corrosion affects the pipe-wall thickness differently. It may be of a uniform nature or localized in extent and severity. Despite considerable anticorrosion protection efforts, corrosion damage occurs on a large scale. In this paper it is further assumed that corrosion affects all sections of a pipeline in a similar manner. In fact, corrosion should endanger the unfortified section more.

BURST PRESSURE – A LITERATURE REVIEW

Modern pipeline codes assume that the design criterion represents the capacity for the appropriate failure mode, i.e. the limit state. For the pressure containment equation, this means the bursting capacity must be determined fairly accurately and with consistency, i.e. the prediction should be a close lower bound of the actual burst pressure. DNV, B31G or similar codes serves this purpose.

Difference between prediction and test results may be due to:-
• The inability of the equations to accurately predict behaviour.
• Errors in yield strength determination; different methods of measurement and subsequent calculation may cause large variation.
• Difference can exist along and around the pipe, so that conventional tensile test results may not capture the minimum properties which determine failure in practice.

No burst equation can escape the random error of wall thickness and the material properties, which results in a COV of 5%.

Burst tests were reported by Coulson (1990), Chouchaoui (1992) Vieth and Kielher (1994), Benjamin et al. (2000), Bjornoy et al. (2000) and Batte et al. (1997) among others. Cronin and Pick (2000) performed burst tests on corroded pipelines removed from service due to corrosion defects.

There are numerous equations for the prediction of pipe burst pressure. Some of these equations have theoretical basis, but most include a correction factor (see e.g. Bea 1999) which are calibrated against a data base and obviously COV should be low. However, caution must be exercised when using them in blind test. Two of these (DNV and B31G) were compared to the results of previously reported burst tests from a number of sources. The actual and predicted burst pressures are given in Table 1, in Appendix, for a few tests reported in the literature (see references cited).

The modified B31G predictive models for pipe rupture or DNV approach are designed to be conservative. Statistical information is provided on the relationship between the predicted failure stress and actual failure stresses obtained from pipe burst tests in the modified ASME B31G are shown in Table 1. As Table 1 shows no predictive tools gives the exact burst pressure. The ratio of the true burst pressure to the predicted value is known as the model bias and defined as:

$$Bias = B_{burst} = \frac{True}{Predicted} = \frac{Measured}{Nominal}$$

The test results were normalised and the average and standard deviation for these percentages are shown in Table 2.

Table 2 Statistics of burst tests of Table 1

Code	Bias	Standard Deviation	COV
ASME	1.036	0.086	0.083
DNV	1.093	0.101	0.093

The bias of DNV predicted to actual failure stress ratio, in these tests was found to have a mean value of 1.09 and a standard deviation of 0.101. Bjornoy et all (2001) compared the DNV equation for corroded pipeline against a selected data base and suggested the bias is about 1.02 and the standard deviation is 0.135. It should be remembered that, measured values determined by experiment are not necessarily true values or actual value under the field condition. Data used in predictive models are also subject to random variation. However, in this paper we are dealing with ratio of burst pressures of unfortified and fortified sections of the pipe and if the same predictive model is used for both, then bias is not an important parameter, but COV is.

Checking DNV equation against Bathe et all (1997) gives a bias of 1.05 and COV=0.095. The maximum COV reported in literature is 22% (Bea RAM project 1999) and the minimum is 5% (Law 2002).

RELIABILITY ANALYSIS

The uncertainty associated with the rate of corrosion and the uncertain location of its occurrence is a major concern. Because of this, it is appropriate to use a probabilistic approach that is more realistic than prescribing some nominal differences on the design pressure. A probabilistic approach provides a quantitative measure of safety and also provides both qualitative and quantitative information about the effects of various uncertain parameters on the safety-measure estimate. For pipelines subject to both internal and external loading, an important failure consideration is that of burst, which is influenced by localized or overall reduction in pipe-wall thickness. Localized loss of wall material arises from pitting and/or crevice corrosion. This is known from experience to be localized, in the sense that only a small part of a pipeline circumference is likely to be affected. Alternatively, such as where protective coating has cracked circumferentially, only a very short local length of pipeline is likely to be affected. More loss of material through general corrosion, which affects much of the circumference, is nearly uniformly or so.

The performance function is defined

$$Z = R_f - R_u \quad (1)$$

Where R_f and R_u are the capacity of fortified and unfortified segments, respectively. We require that

$$Z = R_f - R_u \geq 1$$

If the above inequality is satisfied, then it is probable for the unfortified section to fail before the fortified section. Assuming that R_f and R_u are log-normally distributed, then $Z = R_f - R_u$ is also has a log-normal distribution of $Z \sim (\mu_z - \sigma_z^2)$.

Denoting the probability density function (PDF) by $f_z(Z)$ and the cumulative probability function (CPF) by $F_z(Z)$, respectively, the failure probability P_f of the ILP is

$Z = R_f - R_u \leq 0$ and hence

$$P_{f=}P(Z \leq 0) = \int_{-\infty}^{0} f_z(Z)\, dz = F_z(0) \quad (2)$$

This is shown in Figure 5.

Substitution of PDF of Z into Equation 1, gives:

$$P_f = \int_{-\infty}^{0} f_z(Z)\, dz = \int_{-\infty}^{0} \frac{1}{\sqrt{2\pi}\,\sigma_Z} e^{-\frac{1}{2}\left(\frac{Z-\mu_z}{\sigma_z}\right)^2} dz \quad (3)$$

This can be rewritten as

$$P_f = \frac{1}{\sqrt{2\pi}} \int_{-\infty}^{-\frac{\mu_Z}{\sigma_Z}} \frac{1}{\sqrt{2\pi}\,\sigma_Z} e^{-\frac{t^2}{2}} dz = \Phi\left(-\frac{\mu_Z}{\sigma_Z}\right) \; ; t = \frac{z-\mu_z}{\sigma_z}, \quad (4)$$

Where, Φ is the cumulative probability function for a standard normal distribution.

Since $\beta = \mu_z/\sigma_z$, hence

$$P_{f=}\Phi(-\beta) = 1.0 - \Phi(\beta). \quad (5)$$

For the log-normal diminution, the reliability index β and the failure probability P_f distribution can be expressed as:

$$\beta = \frac{\mu_z}{\sigma_z} = \frac{\mu_{\ln R_f} - \mu_{\ln R_{uf}}}{\sqrt{\sigma^2_{\ln R_f} + + \sigma^2_{\ln R_{uf}}}} = \frac{\ln\left[\frac{\mu_{R_f}}{\mu_{R_{uf}}}\left(\frac{v^2_{R_{uf}}+1}{v^2_{R_f}+1}\right)^{1/2}\right]}{\sqrt{\ln\left[\left(v^2_{\ln R_{uf}}+1\right)\left(v^2_{\ln R_f}+1\right)\right]}} = \frac{\ln\left[FS\left(\frac{v^2_{R_{uf}}+1}{v^2_{R_f}+1}\right)^{1/2}\right]}{\sqrt{\ln\left[\left(v^2_{\ln R_{uf}}+1\right)\left(v^2_{\ln R_f}+1\right)\right]}} \quad (6)$$

μ_{R_f} and $\mu_{R_{uf}}$ are the mean values, and σ_{R_f} & v_{R_f} and $\sigma_{R_{uf}}$ & $v_{R_{uf}}$ are the standard deviations and coefficient of variation of fortified and unfortified section.

The safety factor for ILP is defined as the ratio of the mean values of strength of fortified section and unfortified section. Hence

$$FS = \frac{\mu_{R_f}}{\mu_{R_{uf}}} \quad (7)$$

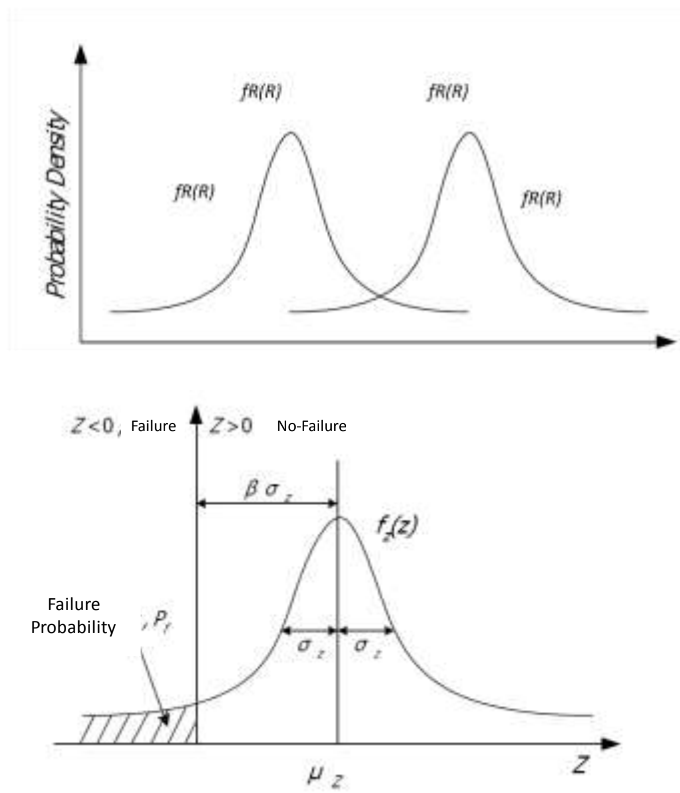

Figure 5- Probability density distribution for the performance function

The failure of ILP, P_f , corresponding to any given safety factor FS can be obtained from Eq. (6). For a specified risk (in terms of reliability) or for a given minimum reliability index βmin, the minimum safety factor (FSmin) to be adopted for design depends on COV of R_f and R_u and can be obtained from Equation 7 as:

$$FS_{min} = EXP\left[\beta_{min}\sqrt{ln\left[v_{lnR_f}^2+1\right]+ln\left[v_{lnR_{uf}}^2+1\right]}+ ln\sqrt{\frac{v_{lnR_f}^2+1}{v_{lnR_{uf}}^2+1}}\right]$$

(8)

From Eq. (8), it is clear that in deterministic analyses where no variability is considered, the minimum safety factor required is equal to one. If there is variability, the safety factor required increases. As variability increases, the required safety factor also increases to achieve the same level of performance or acceptable risk in terms of probability of burst. The minimum safety factor required also increases if the acceptable risk decreases. Generally, the term risk refers to the joint probabilities of “failure” and “failure consequence”. In this paper, however, we are not dealing with the consequences of failure (as this preferential failure is one of several lines of defence); therefore the term risk refers solely to the probability of failure

$$Risk = p(FOS < 1) \qquad (9)$$

TARGET FAILURE PROBABILITY

Generally, design events typically consider a variable annual probability of exceedence per unit pipeline length or pipeline system depending on the safety class and limit state considered. For example, annual probability of exceedance levels for general environmental loads is 10^{-2} per kilometre and for rare events (e.g. earthquake, iceberg impact) or accidental loads (e.g. construction, fire/explosion) the exceedence limit is specified as 10^{-4} per kilometer. The target safety level represents a maximum acceptable failure probability for a defined limit state; that is the minimum acceptable level for a defined hazard. Sotberg et al. (1997) and DNV suggested the annual target safety levels for offshore pipelines as shown in Table 3.

Table3- Annual Target of failure probability

Limit Sate	Target Probability of failure/Km/year
Serviceability	10^{-2} to 10^{-3}
Ultimate	10^{-3} to 10^{-4}
Fatigue	10^{-3} to 10^{-4}
Accidental	10^{-4} to 10^{5}

ASME and other pipeline codes define a number of location classes and require different safety margin for each class based on their criticality. Table 4 gives the target reliability levels implied in ASME code.

The fundamental consideration in setting the target annual failure probability levels is a low probability that the fortified section to fail before the unfortified section. The target values recommended in offshore codes, standards and other published documents were reviewed, generally based on safety classification. Typically, three safety classes of ‘low’, ‘normal’ and ‘high’ are defined. The target failure probabilities recommended for design against a failure condition such as rupture in the technical literature are summarised in Table 5.

Table 4- Target reliability levels for ASME (from 1).

ASME Location Class	Target Probability of failure/Km/year
1	1×10^{-4}
2	1×10^{-5}
3	1×10^{-6}
4	1×10^{-7}

Table 5- Annual Target of failure probability

Source	**Safety Class**		
	Low	**Normal**	**High**
RP-F101	10^{-3}	10^{-4}	10^{-5}
OS-F101	10^{-3}	10^{-4}	10^{-5}
Sotberg et al (1997) SUPERB project	10^{-2} to 10^{-3}	10^{-3} to 10^{-4}	10^{-4} to 10^{-5}

Table 6-Target Reliability Index (Life time) –From Annex of ISO2394

Relative costs of safety measures	**Consequences of failure**			
	Small	**Some**	**Moderate**	**Great**
High	0	1.5	2.3	3.1
Moderate	1.3	2.3	3.1	3.8
Low	2.3	3.1	3.8	4.3

Table 7 - Relationship between reliability Index (β) and probability of failure (p_f)

Reliability Index β	Probability of failure $p_f = \Phi(-\beta)$
1	0.159
1.5	0.0668
2	0.0228
2.5	0.00621
3.0	0.00135
3.5	0.000233
4.0	0.0000316
$\Phi(\cdot)$ standard Normal probability distribution	

Table 6 shows an example of the reliability index as given in the annex of ISO2394. It suggests that high reliability index should be used to improve safety where failure would cause harm to people, and in areas of no concern the basic safety margin is adequate. The reliability index corresponds in design life of the structure, and it has one-to-one relationship with failure probability

CASE STUDY- PROTECTION PHILOSOPHY

The study field is a high pressure gas development located in water depths ranging from 70m to 580m. The development consists of a series of subsea manifolds and associated well clusters tied back to a fixed platform by flowlines. On the platform topsides, the flowlines are linked to the inlet separators via a number of topsides manifolds. A typical schematic detailing the arrangement for the flowlines tied back to a production platform is shown in Figure 6.

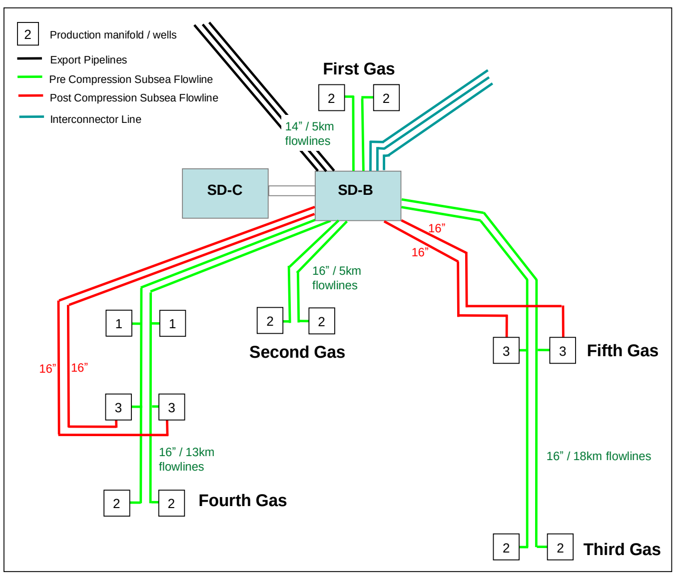

Figure 6- Flowlines Schematic

The basis of design for the subsea wellheads is for a maximum shut-in tubing head pressure (SITHP) of 835 barg which includes a bullheading allowance of 35 bar.

The selected pressure protection design for each flowline / riser is based on:

- a subsea HIPPS system, that allow the flowlines downstream of the subsea HIPPS to be rated below the SIWHP
- fortified sections adjacent to subsea wellheads / manifolds and the platforms, to provide confidence that a failure would preferentially occur in the non-fortified section
- a SSIV located upstream of the platform, that allows the topsides to be isolated from a well event in the event of subsea HIPPS failure

The design involves a subsea HP / LP interface, as the subsea flowlines from the production manifolds are not rated to the shut in wellhead pressure.

The design option considered in this assessment (see Figure 7 in Appendix) comprises:

- the subsea trees and manifold up to the subsea HIPPS valves on the manifolds being fully rated for the SIWHP
- the flowlines downstream of the subsea manifold being fortified for a short distance
- the flowlines adjacent to the platform being fortified for a short distance
- the riser rated to ASME 2500#
- the topsides inlet pipework rated to ASME 2500# (up to the topsides HP/LP interface); and
- the flowlines between the two fortified zones being unfortified, and rated to a design pressure of 270 barg

The design of the fortified subsea flowlines is such that the flowlines are either:

- designed such that the associated burst pressure is above the SIWHP, or
- designed such that the likelihood of failure of the fortified section before the unfortified section is low

- The rationale for the fortified sections is that although the design could be demonstrated to be acceptable via a wholly instrumented / valve design, fortified sections provide an inherently safer design providing confidence that a failure would preferentially occur in the non-fortified section.
-
- The acceptability of the selected design option is also based on the hydro-testing strategy, where the installed riser / spool-piece and associated connections (except last connection at fortified / non-fortified boundary) are required to be hydro-tested offshore to a minimum of 1.4 times the ASME 2500# design pressure.

The process shutdown is considered to comprise the following main steps, based on the initiating event of a topsides production trip:

- Topsides production trip initiates closure of choke valve and subsea production wellhead valves (PMV / PWV) via the MCS
- If pressure continues to rise, a subsea pressure trip initiates closure of choke and subsea production wellhead valves (PMV / PWV) via the MCS

➢ If pressure continues to rise, a subsea pressure trip initiates closure of choke and subsea production wellhead valves (PMV / PWV) via the SCM
➢ If pressure continues to rise, an autonomous pressure trip initiates closure of the subsea manifold HIPPS valves
➢ If pressure continues to rise, a topsides pressure trip via the ESD system initiates topsides venting of the subsea HP / LP hydraulics (to effect closure of the subsea well / manifold valves)

The subsea HIPPS is provided via a single system located on the manifold. The required integrity is IL 3 with a PFD < 8.3E-4.

There are several events that could lead to an overpressure hazard for pipelines and risers, these include:

➢ Topside train / production shutdowns with associated subsea isolation failure or leakage across isolation valves.
➢ Blocked flowline (hydrate, spurious SSIV closure, stuck pig (subsea launched)) with associated subsea isolation failure or leakage across isolation valves.

Topside shutdowns are considered the most likely initiating event. It is assumed topside shutdown frequencies in the order of once per month, i.e. 12 events per year.

Other events that might lead to blockages in the production system are:

➢ Hydrate formation
➢ Wax formation
➢ Stuck pig
➢ Spurious valve closure (e.g. SSIV)

These events are expected to have a low probability of initiating an overpressure hazard for pipelines and risers. This statement is based on the following considerations:

➢ Hydrate formation - the most likely areas for hydrate blockage are in low temperature small diameter pipe-work downstream of the choke valve, which are fully pressure rated.
➢ Wax formation - wax is expected to be present in the flowline only in late life of field. Wax build up is considered very slow and very detectable (1 - 3 months estimated per 2mm build up on pipe wall) and therefore a blockage due to wax formation very unlikely to happen.
➢ Stuck pig - Overpressure is only possible if pig is driven by production fluids (thus a subsea pigging operation). The design reference case is for pigging to be driven by topsides fluids.
➢ SSIV spurious closure - indicative spurious closure frequencies of ~ 5 x 10^{-2} / yr

Topside shutdowns are considered the most likely initiating event that could lead to an overpressure hazard. The process shutdown steps are considered to comprise the main steps, based on the initiating event of a topsides production trip, as listed earlier in this section.

In addition to the valves listed above, a tree isolation valve (TIV) is located on the production tree (downstream of the choke), and a branch isolation valve or slot valve located in-between the multi-flow meter and manifold. These valves are actuated and could be configured as part of the process shutdown steps in order to reduce the demand on the subsea HIPPS system. The acceptability for using isolation valves for shutdown purposes would need to be established before such a measure was implemented. It should be noted that these valves were not considered within the subsea LOPA, with no credit taken for their closure.

The probability of failure of this system was determined to be <E-3. In order the complete arrangement to qualify for defence in depth, the probability of failure should be less than E-5. This indicates that the target reliability index for the preferential pipeline failure is 2.325, using COV=0.11, leading to a failure rate of less than E-2. Substituting this in Equation (8) and assuming 0.11 as the coefficient of variation for both segments the minimum safety factor is determined to be 1.43. A safety factor of 1.22 gives the probability of failure of about E-1 which is equivalent to the reliability 1.28.

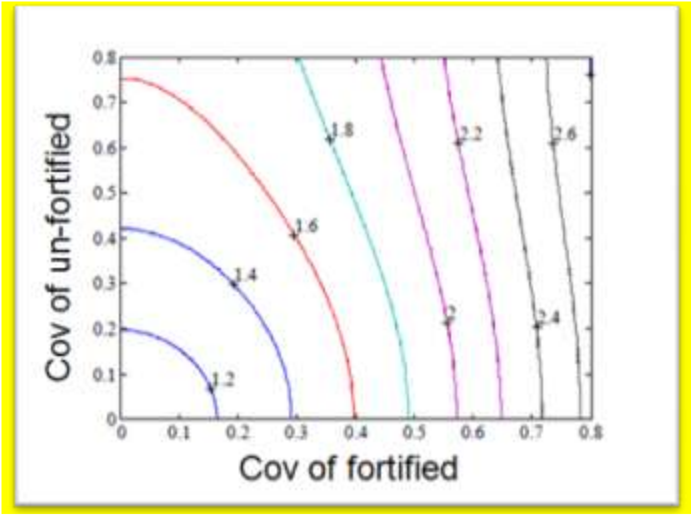

Figure 8 Contours of the minimum safety factor required for varying COVs of un-fortified and fortified sections (for failure probability P_f of the ILP equal to 0.15)

As variability increases, the required safety factor also increases to achieve the same level of performance or acceptable risk in terms of probability of failure. The minimum safety factor required also increases if the acceptable risk decreases. Equation (8) is plotted in Figure 8 and it can be seen that the minimum *FS* required is more dependent on variability in fortified than in unfortified. For

$COV_{fortified} > 0.4$, the *FS* is dominated by $COV_{fortified}$ irrespective of the value of $COV_{unfortified}$.

CONCLUSIONS

In this paper, a method was presented for the estimation of the preferential failure pipeline under unforeseen overpressure; if it is desired to consider a design as an IPL. Uncertainties involved in material, internal and external loads and corrosion parameters are considered through the use of reliability theory.

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ANNEX A

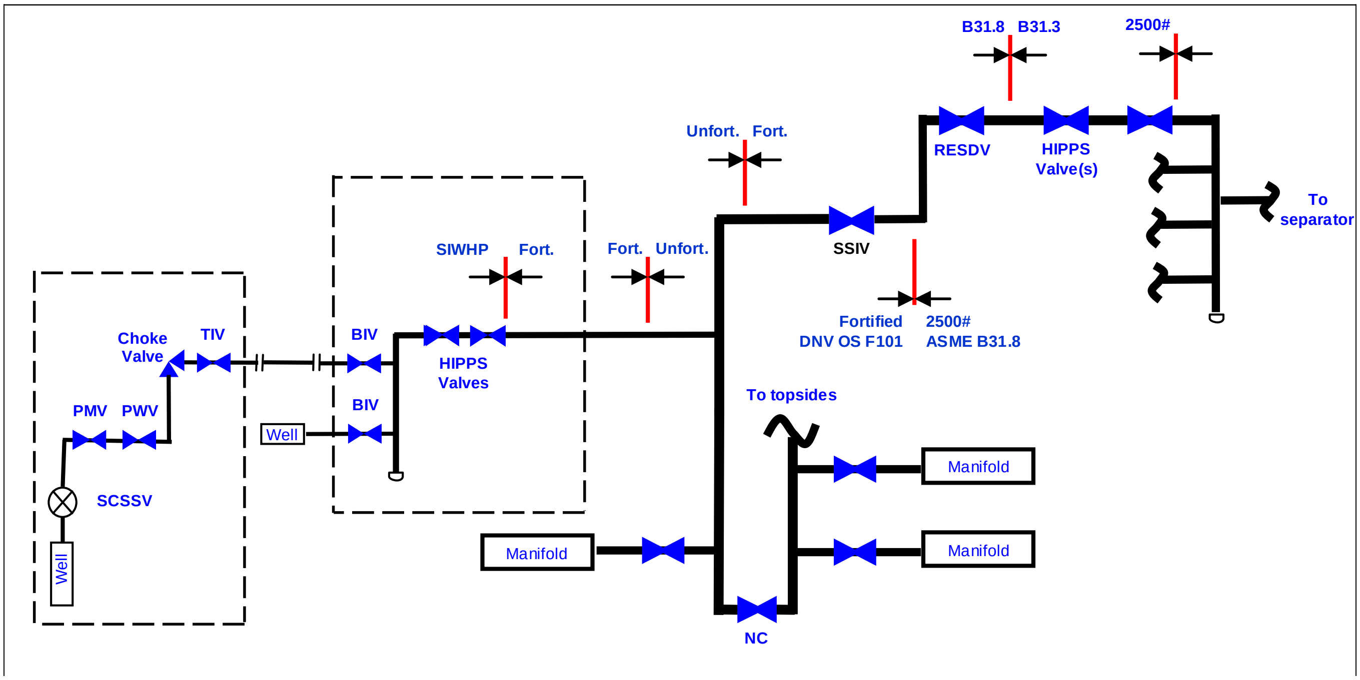

Figure 7 – System Schematic

Table 1: Burst tests complied from literature

Test Cae	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17
YS	509	624	532	555	534	441	512	501	517	458	509	427	636	563	607	619	622
TS	572	624	608	580	653	585	600	581	559	546	605	578	645	589	630	716	716
e u	0.09	0.01	0.12	0.09	0.11	0.15	0.12	0.13	0.09	0.1	0.11	0.14	0.05	0.1	0.14	0.09	0.1
t	14.81	13.49	19.99	19.99	15.9	15.9	15.9	15.9	19.05	19.05	19.05	19.05	19.05	19.05	19.05	14.12	14.1
D	508	543.6	762	762	609.6	609.6	609.6	609.6	914.4	914.4	914.4	914.4	609.6	609.6	609.6	1117.6	1117.6
n	0.09	0.013	0.112	0.087	0.105	0.135	0.112	0.126	0.089	0.097	0.104	0.135	0.046	0.095	0.127	0.09	0.091
Ro	254	271.8	381	381	304.8	304.8	304.8	304.8	457.2	457.2	457.2	457.2	304.8	304.8	304.8	558.8	558.8
Ri	239.2	258.3	361	361	288.9	288.9	288.9	288.9	438.2	438.2	438.2	438.2	285.8	285.8	285.8	544.7	544.7
K = Ro/Ri	1.06	1.05	1.06	1.06	1.06	1.06	1.06	1.06	1.04	1.04	1.04	1.04	1.07	1.07	1.07	1.03	1.03
Sec Mod	6080	47993	5153	6371	5882	4032	5083	4337	6012	5353	5503	4017	13715	5894	4667	7577	7537
V eff	0.49	0.45	0.49	0.49	0.49	0.5	0.5	0.5	0.49	0.49	0.49	0.5	0.49	0.49	0.5	0.49	0.49
YT	0.89	1	0.87	0.96	0.82	0.75	0.85	0.86	0.92	0.84	0.84	0.74	0.99	0.96	0.96	0.86	0.87
D/t	34.31	40.3	38.12	38.12	38.34	38.34	38.34	38.34	48	48	48	48	32	32	32	79.14	79.28
Test result	35.8	33.8	30.6	32	34.8	31.8	31.7	30.2	24.8	23.1	25.8	23.2	40.7	36.4	39	21.8	21.7
ASME	34.1	31.6	32.6	31.1	34.8	31.1	32	31	23.7	23.1	25.6	24.5	41.3	37.8	40.4	18.3	18.2
DNV	32.4	31.7	30.7	30.6	31.8	27.5	29.8	29	22.9	21.4	23.7	21.4	41.3	37.2	39.9	17.1	17.1