

# ED Inspection Guide Offshore

## Inspection of Loss of Containment (LOC)

**Open Government status: Fully Open**

**Target audience: HSE ED Inspectors**

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### SUMMARY

This document is intended to provide guidance to Energy Division staff to support inspection of loss of containment risk at offshore oil and gas installations. It describes a number of key elements which contribute to effective management of the risks, based on research into root causes of previous incidents, and published industry codes, standards and good practice. It also identifies relevant legislation, matters of evident concern, benchmark standards and examples of good practice for each element, in order to support performance assessment. Areas where additional specialist support may be useful or necessary are identified.

It is important to note that the guide does not cover a number of aspects which are fundamental to management of loss of containment risk, where the technical lead is taken by other HSE specialist teams, and/or other inspection guidance exists. This includes for example the design, inspection and maintenance of pressure systems, control of work (including permit to work) and several human factors topics.

## **INTRODUCTION**

The aim of this Inspection Guide (IG) is to provide information and guidance to offshore inspectors to support the delivery of consistent and effective inspection of process safety systems which protect against loss of containment. It does this by highlighting current key areas to be covered during inspections, providing a framework for inspectors to judge compliance, assign performance ratings, and decide what enforcement action to take should they find legislative breaches. In doing so, it complements HSE's **Enforcement Policy Statement** (EPS) and **Enforcement Management Model** (EMM).

Various regulations (described more specifically later) place duties on operators of offshore installations to take measures to minimise the risk of a loss of containment of flammable, toxic or hazardous substances. These measures must be effective throughout the installation's lifecycle, and under all foreseeable plant conditions

This guide is split into twelve core intervention areas as follows:

- 1 Process Plant design, construction and commissioning
- 2 Process Plant operation within safe limits
- 3 Instrumented Protection Systems
- 4 Relief, Blow-down and Flare systems
- 5 Process Isolations
- 6 Plant Re-instatement following Maintenance or Idle Phase
- 7 Management of Change
- 8 Other Offshore Process Hazards
- 9 Monitoring & Review Arrangements
- 10 Positive Process Safety Culture
- 11 Floating Production, Storage and Offloading (FPSO Installations)
- 12 Management of small bore tubing, piping and flexible hoses

An overview of each of the above will be provided in appendices 1-12. The effectiveness of the measures taken under each area is key to ensuring that a duty holder minimises the likelihood of a major accident hazard occurring. Appendix 13 provides generic guidance on assessing duty holder performance using the inspection guide.

## **ACTION**

A complete inspection of this topic requires all intervention areas to be addressed, although some may be of greater relevance to a particular installation given its inherent hazards, performance history and position within its own lifecycle. For the purposes of assessing the performance of a duty holder, the scope of the intervention areas to be inspected should be agreed in advance between the IMT and other specialist inspectors assigned. Individual appendices provide detail on relevant standards and good practice that are expected in general terms, but inspectors will need to devise suitable question sets and other inspection approaches to assess the level of compliance against the quoted benchmarks, based upon the scale and nature of hazard at particular installations.

## **BACKGROUND**

ED's main concern is the prevention of major hazard incidents, in which workers are killed or injured. Major fires and explosions, such as those that occurred on Piper Alpha and Macondo (Deepwater Horizon), have been initiated by releases of hydrocarbons. As such, the effective design and implementation of measures to prevent such losses of containment is fundamentally important.

Typical sources of hydrocarbon releases (HCRs) are the well, the pipeline riser, other pipelines and pipe work and associated process plant. Releases can occur from either failure of the asset itself due to corrosion, abrasion or fracture, or because of failures of maintenance e.g. poor practice when breaking and re-making joints, or insufficient operational controls. HCRs can also result from damage due to other failures e.g. dropped objects during crane operations.

## **TARGETING**

Inspections should be planned within the timescales set out by ED divisional management. Although inspections may be carried out at any installation, it is particularly important to carry this out where there are known issues that may affect process integrity, such as ageing equipment, major work over projects etc. It is essential to ensure that duty holders are robust in their assessment of the implications of these factors, that suitable mitigations are in place and that cumulative risk factors have been considered.

## **TIMING**

Inspectors should undertake loss of containment interventions as part of the agreed ED offshore intervention plan, when intelligence indicates intervention is necessary, or when investigation due to incident is required.

## **RESOURCES**

ED3.1 (Process Engineering) has overall ownership of the guide, and takes the lead on inspecting several of the elements. Some however are more closely aligned to other specialist teams (such as EC&I for appendix 3, and

Mechanical Integrity for appendix 12). Appendices 7, 9 and 10 describe inspection of particular process aspects of duty holders' SEMS, and as such are closely aligned with IMT. Most of the elements will benefit from a multidisciplinary approach to their inspection.

## RECORDING AND REPORTING

The duty holder performance ratings should be entered on the Inspection Rating Form (IRF) tab of the relevant installation Intervention Plan Service Order. Findings should be recorded in the normal post inspection report and letter.

## APPLICABLE LEGISLATION

The table overleaf provides a cross reference of applicable legislation against the relevant sections of this inspection guide. All legislation is available to download from [www.legislation.gov.uk](http://www.legislation.gov.uk). A list of applicable HSE publications, e.g. Approved Code of Practice, is also provided with these documents available from [www.hse.gov.uk](http://www.hse.gov.uk)

## SPECIALIST ADVICE

ED 3.1 can provide general/initial advice on all of the elements. Other units may however be able to provide additional or more authoritative guidance for particular aspects related to their discipline, as suggested below.

Appendix	Title	ED Unit
1	Process Plant Design, Construction and Commissioning	ED 3.1
2	Process Plant Operation within Safe Limits	ED 1/ED 4.6
3	Instrumented Protection Systems	ED 3.5
4	Relief, Blow-down and Flare Systems	ED 4.1
5	Process Isolations	ED 4.1
6	Plant Re-instatement following Maintenance or Idle Phase	ED 4.1
7	Management of Change	ED 1
9	Monitoring & Review Arrangements	ED 1
10	Positive Process Safety Culture	ED 1/ ED 4.6
11	Floating Production, Storage and Offloading (FPSO) Installations	ED 4.3
12	Management of Small Bore Tubing, Piping and Flexible Hoses	ED 4.1

Regulation	Loss of Containment Guide Section												
	1	2	3	4	5	6	7	8	9	10	11	12	13
<b>Control of Substances Hazardous to Health Regulations, 2002</b>													
Regulation 6								X					
Regulation 7								X					
<b>Management of Health and Safety at Work Regulations, 1999</b>													
Regulation 3	X		X			X	X				X		
Regulation 4	X												
Regulation 5	X	X	X		X	X		X	X	X	X	X	X
Regulation 10		X											
Regulation 11	X												
Regulation 13		X											
<b>Offshore Installations (Prevention of Fire and Explosion, and Emergency Response) Regulations, 1995</b>													
Regulation 4													
Regulation 5			X	X							X		
Regulation 9	X	X	X	X	X	X		X		X	X	X	X
Regulation 10								X					
Regulation 12				X									
Regulation 19	X		X	X			X	X					X
Regulation 21		X											
<b>Offshore Installations and Pipelines Works (Management and Administration) Regulations, 1995</b>													
Regulation 11		X			X								
<b>Offshore Installations and Wells (Design and Construction, etc) Regulations, 1996</b>													
Regulation 5	X												
Regulation 6	X												
Regulation 7		X											
<b>Offshore Installations (Offshore Safety Directive) (Safety Case etc) Regulations, 2015</b>													
Regulation 7									X				
Regulation 8									X				
Regulation 32									X				
<b>Provision and Use of Work Equipment Regulations, 1998</b>													
Regulation 4	X												
Regulation 5			X					X					X
Regulation 6	X		X										X
Regulation 8	X	X						X			X	X	
Regulation 9	X	X									X	X	
Regulation 12	X												
Regulation 23					X						X		

Note: that the Health and Safety at Work etc. Act 1974, Sections 2(1) and 3(1) outline the overarching duty and is applicable to all sections of this guide.

## **APPENDIX 1 – PROCESS PLANT DESIGN, CONSTRUCTION AND COMMISSIONING**

### **Scope**

This guidance applies to the inspection of systems which provide safety assurance for the design, construction and commissioning phases of offshore oil or gas production process plant.

### **A) PROCESS PLANT DESIGN**

#### **Fundamental Requirements**

The design of a process plant is a complex activity that will usually involve many different disciplines over a considerable period of time. The design may also go through many stages from the original research and development phases, through conceptual design, detailed process design and onto detailed engineering design (drawings, calculations, specifications etc.) and equipment selection. Many varied and complex factors including safety, health, the environment, economic and technical issues may have to be considered before the design is finalised. At each stage it is important that the personnel involved have the correct combination of technical competencies and experience in order to ensure that all aspects of the design process are being adequately addressed.

The principles of inherently safer design are particularly important for major hazard plants and should be considered during the design stage where there is the greatest potential for reducing the risk of loss of containment, in an effort to reduce the hazard potential of the plant. Consideration should be given to processing hydrocarbons under conditions that make the materials less hazardous (e.g. at lower temperatures and pressures).

Consideration should also be given to complexity reduction where appropriate. Having a simpler design can also improve the overall safety of the plant because more complex plants may provide more opportunities for error in design, construction, commissioning and operation.

A number of principles should be adopted:

- Hazards and risks implicit in the design should be identified.
- Engineering design should use a hierarchical approach to minimise risk (avoid, substitute, reduce, adapt, technical controls, procedural controls, and other measures which protect groups over those which protect individuals).
- Appropriate and up to date industry standards should be used.
- Equipment that is safety critical should be capable of maintaining its integrity throughout its life, taking account of normal as well as foreseeable extreme operating loads.
- The materials used should be suitable for the process and the environment.

- All equipment that is safety critical should have adequate and defined reliability, availability and survivability.
- The overall risk assessment and selection of options must have regard to the intended life cycle, including offshore construction, commissioning, operation, maintenance, foreseeable modifications and eventual decommissioning or disposal.

The opportunity to achieve an inherently safer design is greatest for new plant and equipment and wherever reasonably practicable, the same approach should be followed for plant modifications.

An example of inherent safety in design in the case of over-pressure hazards is that installations should preferably be designed to have fully rated risers, vessels, pipework and pipelines. If the topsides are not fully rated, a hierarchy of over-pressure protection measures should have been considered including: full flow relief; partial relief with instrumented protection system; HIPPS, etc.

Design for brownfield modification projects should follow the same general principles and such modifications should be subject to a management of change process where the risks should be identified and suitably assessed. Care should be taken when integrating new and old systems; it may not be reasonably practicable to fully upgrade an existing system as a result of a brownfield modifications. Justification of the boundaries of the modifications needs to be fully understood and assessed accordingly.

### **Hazard identification**

Process risks, and loss of containment scenarios in particular, should be identified via installation specific hazard studies. These should be carried out in accordance with recognised standards or codes of practice, and include, but not be limited to, such studies as HAZOP, HAZID, Functional Safety assessment, SIL assessment, LOPA etc. The outputs of such studies should preferably be a full recording of the assessments made, rather than just a record of any issues or actions arising and confirmation that any issue or actions arising have been appropriately resolved. Full recording supports a demonstration that the process has been thorough, and ensures that any basis or assumptions are clear.

The hazard identification should involve the appropriate mix of disciplines/expertise in order to be effective and it is important to involve operations personnel who will be responsible for the day to day running and operation. Independent experts should also be involved. Where vendor supplied equipment is also present, these should be subject to the same hazard identification process as per the rest of the installation.

HAZOP and / or other safety studies should be carried out at the design stage though may be revisited during subsequent phases of the project. Action lists should be produced and an action tracking system set up. All actions should be closed out (i.e. completed & signed off) at an appropriate stage in the project lifecycle.

For additions to existing process plant, it is important that all factors affecting the existing plant have been identified and addressed and in some cases a new HAZOP may be required depending on the nature of the changes or additions.

## **Equipment Design**

The mechanical design of vessels, pipework, pipelines and ancillary equipment has a critical impact on loss of containment risk. All equipment and systems which have the potential to cause or contribute to a MAH should be included. This area is currently outside of the scope of this guide, but includes consideration of topics such as corrosion, erosion, fatigue/vibration, brittle fracture, rotating equipment seal design, bolted joints, mechanisms of ageing/degradation etc. Design measures are numerous, and include approaches such as appropriate selection of materials (use of corrosion resistant alloys, low temperature resistant metals), minimisation of flanges through use of all-welded pipework, minimisation of the use of small bore tubing, minimising use of insulation (corrosion under insulation risk) etc. The mechanical engineering team (ED4.1) should be consulted for further support on these topics.

## **Industry Standards and Guidance**

### Inherently Safer Design

- BS EN ISO 13702:2015 'Petroleum and Natural Gas Industries - Control and mitigation of fires and explosions on offshore production installations - Requirements and guidelines'
- Energy Institute Publication 'Guidance on applying inherent safety in design: Reducing process safety hazards whilst optimising CAPEX and OPEX', Second Edition, 2014

### Hazard Identification and Assessment Techniques

- API RP 14C 'Analysis, Design, Installation and Testing of Safety Systems for Offshore Production Facilities', Eighth Edition, 2017
- BS EN ISO 10418:2003 'Petroleum and Natural Gas Industries – Offshore Production Installations – Analysis, design, installation and testing of basic surface process safety systems'
- BS EN ISO 17776:2016 'Petroleum and Natural Gas Industries – Offshore Production Installations – Major Accident Hazard management during design of new installations'
- BS EN 60812:2006 'Analysis techniques for system reliability – Procedure for failure mode and effects analysis (FMEA)'
- BS EN 61025:2007 'Fault Tree Analysis (FTA)'
- BS EN 61882:2016 'Hazard and operability studies (HAZOP studies) - Application guide'
- IChemE Publication 'HAZOP: Guide to Best Practice', Third Edition, 2015

## Relevant HSE guidance

- HSE Publication L65, 'Prevention of fire and explosion, and emergency response on offshore installations - Approved Code of Practice and Guidance', Third Edition, 2016
- HSE Publication L22, 'Safe use of work equipment, Provision and Use of Work Equipment Regulations 1998 - Approved Code of Practice and Guidance', Fourth Edition, 2014
- HSE Publication L85, 'A guide to the integrity, workplace environment and miscellaneous aspects of the Offshore Installations and Wells (Design and Construction, etc.) Regulations 1996 – Guidance on Regulations', 1996

## Inspection Approach

- Identify which hazard identification and assessment studies have been carried out. Assess if the range and scope is appropriate. Sample to confirm that all relevant process hazards have been identified, assessed, and suitable measures selected. Consideration should also be given as to whether the concept of Inherently Safer Design has been incorporated.
- Check for a sample of the measures selected, that these have been implemented on the installation.
- Check for a sample of the actions arising from the hazard identification studies that these have been completed, and review in more detail any that appear to be unresolved.
- Request copies of key design paperwork (typically P&IDs, basis of design, datasheets, cause & effect charts) for a sample process plant system (e.g. gas compression) and check that these are internally consistent, clearly laid out, and meet expectations of good engineering practice for such documentation.

## Matters of Evident Concern

Inspection finding	Examples
Inadequate hazard assessment and identification of suitable measures	<ul style="list-style-type: none"><li>• No evidence of recent hazard assessments, e.g. 5-yearly re-HAZOP of installation</li><li>• Hazard assessments completed but number of actions outstanding</li></ul>
Suitable measures not implemented	<ul style="list-style-type: none"><li>• Hazardous assessment actions have been identified as completed but not implemented at site, e.g. plant change not carried out</li></ul>

## **B) PROCESS PLANT CONSTRUCTION (OFFSHORE)**

### **Fundamental Requirements**

There should be a project safety plan, and all personnel, including third parties, should have been made aware of the overall aims of the project and how health and safety aspects are integrated into the plan.

Safety and Environmental Management System (SEMS) interfaces should have been clarified. If more than one SEMS applies, measures should be in place to ensure that there are no conflicts and that all relevant information has been effectively communicated to all parties.

The design phase should have been agreed and frozen prior to commencing construction activities in order to eliminate the need for changes of design during construction. Some changes may however be unavoidable and therefore a procedure should be in place for controlling changes arising from construction and commissioning.

A structured mechanism for risk assessment should be in place. Risk assessment procedures, relating to construction and commissioning activities, should have been made available to all relevant parties, and risk assessments should adequately reflect potential consequences. Lessons learned from incidents during similar activities should be discussed during risk assessments and be an important part of the project safety plan.

A study of all potential hazards, arising out of the construction phase, should have been carried out (e.g. analysis of activities such as lifting adjacent to or over, live process plant). Procedures should have been developed covering precautions required for these.

Systems should be in place to check and confirm that all equipment has been procured and installed in accordance with the intended design. This may include a number of stages of checking, both on the installation, but also throughout the equipment supply chain (e.g. at suppliers premises, in construction yard) and involve a range of parties including independent verification by the ICP where required. Arrangements should include provision for:

- Checking that equipment provided meets the original equipment specification including any in-built protection features / risk reduction measures.
- Checking of material specifications of supplied equipment and any associated software
- Checking of correct orientation of installed equipment, and other dimensional and layout details
- Recording of torque / tension settings and joint tagging for critical joints

- Independent checking of the assembly of critical joints to confirm correct use of joint materials, fasteners, flange condition, joint compression, and pipework alignment

It is essential that any changes to the design, arising during the construction phase are subject to formal management of change controls including risk assessment, and are well documented, and controlled. Modifications such as re-routing pipework around obstructions, or tie-ins into existing plant at different locations from the design, or altering the elevation/location of a PSV (which could affect draining of the discharge line into the flare header) would be typical of such changes for which the process consequences may not be appreciated, and hence may not be properly assessed. It is essential therefore that effort is made to raise awareness of the risks of such changes amongst construction personnel. The construction phase should also take into account any potential impact on safety systems as a result of the work being undertaken. Where safety systems may be impacted, rigorous controls should be in place to ensure that the safety systems remain available or appropriate mitigation measures are available and functional.

Persons installing safety and environmentally critical equipment (SECE) such as piping, tubing, instrumentation and other protective systems must be competent to do so. Systems should be in place to provide assurance of such competency.

It should be noted that these principles discussed here are equally applicable to situations such as turnaround maintenance where construction/installation works are being undertaken.

### **Industry Standards and Guidance**

- IOGP Report 423 'HSE Management - guidelines for working in a contracting environment'
- Energy Institute Publication 'Managing Contractors – A Guide for the Energy Industry', 2006

### **Relevant HSE guidance**

- HSE Publication L22, 'Safe use of work equipment, Provision and Use of Work Equipment Regulations 1998 – Approved Code of Practice and Guidance', Fourth Edition, 2014
- HSE Publication L85, 'A guide to the integrity, workplace environment and miscellaneous aspects of the Offshore Installations and Wells (Design and Construction, etc.) Regulations 1996 – Guidance on Regulations', 1996.

### **Inspection approach**

- Identify if a dossier is available for each equipment item containing relevant construction information such as inspection and material certificates. Is it readily available and accessible? Note that inspection should be limited to any recent plant modifications.

- Carry out a line walk on the installation to verify that the P&IDs are a true reflection of the plant as constructed.
- Review any changes made during construction and assess if the effects of the changes have been assessed appropriately. Identify if there may be any impact to the design intent of the plant or if the changes may affect safety critical equipment.

### Matters of Evident Concern

Inspection finding	Examples
Construction phase documents not available	<ul style="list-style-type: none"> <li>• Documents including the material test certificates and QA checks, Inspection and acceptance tests and appropriate handover documents are not available for inspection.</li> </ul>
No red-line mark-ups and as-built documents and drawings produced	<ul style="list-style-type: none"> <li>• No red-line mark-ups of the project documents were produced during construction and commissioning which captures any errors identified or changes made.</li> <li>• No as-built drawings were produced on completion of construction and commissioning activities to ensure any changes from design to installation have been captured.</li> </ul>
Impact of changes not suitably assessed	<ul style="list-style-type: none"> <li>• Changes made during the construction stage have not been suitably assessed to identify the impact of these changes to the design intent.</li> </ul>

## **C) PROCESS PLANT COMMISSIONING**

### **Fundamental Requirements**

Commissioning of process plant is the practical test of the adequacy of prior preparations, including training of operating personnel and provision of adequate operating instructions. This phase includes activities such as system/piping configuration checks and line walks, cleaning / flushing, drying, pressure / leak testing, calibration and function testing. Since the possibility of unforeseen events cannot be eliminated during this period when the system is being tested and operating experience is being gained, the need for safety precautions should be reviewed. This should form part of the risk assessment process applied to the installation.

Full written commissioning procedures should have been produced, approved and made available to all relevant parties.

A project document control system should cover the approval, distribution and checking of project documentation, to ensure all parties work with the most up to date version at all times.

Responsibilities should be clearly assigned. Where projects involve the installation and commissioning of vendor packages there can be a breakdown of responsibilities if this is not adequately controlled. For example where vendor packages are assembled and pressure tested onshore then partially disassembled for shipment, the parties involved may include vendor package expert, hook-up contractor, and maintenance and operations personnel.

Process pipework and vessels should be cleaned / flushed to remove debris (scale, slag etc.). Flushing processes are normally carried out using a high volume flow of a compatible fluid, such as fresh water, but special fluids such as hydraulic oil for a hydraulic system, may be used so as not to contaminate the system. Where seawater is used for flushing it should be inhibited as required. Some systems, e.g. stainless steel, may require fresh water flush, following seawater, to remove chlorides.

Following water flushing, the system is drained at low points; residual water may be blown out of the system using dry air. Where the system is to be left empty for more than a few days, it should be blanketed with dry air or nitrogen to prevent internal corrosion. For prolonged periods in this state, the system may need to be treated with corrosion inhibitor.

Procedures should be in place to control pressure / leak testing. Wherever practicable, hydraulic testing should be employed to reduce the risks to personnel.

Strength testing is carried out to prove the quality of materials and the construction of the equipment / system before it is; installed, enters service or following on site modification, i.e. welding. Test pressure is typically 1.25 - 1.5

x system design pressure. All temporary connections must be adequately rated for the test.

Pneumatic leak testing is normally carried out to identify leaks prior to hydrostatic testing or reinstatement testing at higher pressures. Testing with soap (or proprietary) solution or inert gas with tracer is commonly carried out. The methodology for performing the leak test should be defined, including aspects such as:-

- Suitable locations and equipment for applying the test pressure
- Choice of test fluid
- Consideration of requirements for pressure relief
- Systematic recording of which joints have been inspected, and the method of checking for leaks (what constitutes pass/fail?)
- Safe means of venting the pressure and disconnection at the end of the test.

Function testing may be carried out using a suitable test medium at design pressure, or working pressure if this is lower. The testing should check the function of components including the actuation of moveable parts, and successful activation of instrumented protective systems. Function testing should be planned, with acceptable test criteria defined, and records of its completion made. Sign-off of the results, by an appropriate level of management, should be required.

A system should be in place to identify faults arising during construction and commissioning phases, and track them to completion. 'Punch-lists' are normally used to collate such problems, prioritize corrective actions, and ensure that they are resolved to an appropriate timescale. Punch list items are typically prioritised according to the phase of the project by which they need to be resolved (e.g. before construction to commissioning handover, before leak test, before function test, before start-up, within 1 month of start-up etc.). It is essential that project processes ensure that commissioning activities do not progress to the next phase, until all relevant punch-list items have been completed. Loss of containment events have arisen as a result of failure to effectively manage punch-list items, either in the period leading up to start-up (e.g. leak test not completed/thorough), or even some months later (e.g. damaged or missing insulation, or failure to plug or blank off open ends of small bore pipework). The risk is that some punch-list items are perceived to be a low risk, and consequently not progressed in a timely manner.

Relevant operating procedures should have been developed, reviewed, approved and formally issued in advance of commissioning. Where there have been additions, or modifications, to existing process plant, procedures should be updated to reflect the changes. Many potential hazards can be realised during start-up or shut-down of plant or process. Specific operating procedures should be provided which take account of all foreseeable eventualities.

As part of the commissioning process, some inhibits and overrides of the control and/or protective system may be required to enable testing to be carried out. A record of all inhibits/overrides/bypasses should be maintained and they should only be applied subject to a documented risk assessment and should be removed when no longer needed. Refer to appendix 3 for more information on overrides and inhibits.

Adequate arrangements should be in place for the training of operators and technicians. Training can commence when the design has been fixed (i.e. approved for construction) and operating procedures become available. For vendor packages, it is beneficial for operators and technicians to gain familiarity with the equipment, by becoming actively involved in the commissioning and working alongside the vendor's personnel. Without this involvement the risk is that packages are handed over to installation personnel who have only limited practical knowledge of how to maintain and operate them.

Once any leak and function testing has been completed, arrangements must then be made to ensure the valves and systems are all properly lined up before the first introduction of process fluids. Management checks should be made to ensure that all aspects of the preparation phase of the commissioning are complete, before authority is granted to allow any start-up to proceed.

Once commissioning has been successfully completed, it is important to have a system to effectively record the as-built condition of the plant before handover. This could involve updating documents such as P&IDs and datasheets to capture any changes or modifications made during construction and commissioning.

### **Industry Standards and Guidance**

- ASME B31.3 Code for Pressure Piping (topsides pipework) covering pressure testing of process pipework.
- API RP 14C 'Analysis, Design, Installation and Testing of Safety Systems for Offshore Production Facilities', Eighth Edition, 2017
- BS EN ISO 10418:2003 'Petroleum and Natural Gas Industries – Offshore Production Installations – Analysis, design, installation and testing of basic surface process safety systems'
- DNVGL-DNV-RP-A205 'Offshore Classification Projects – Testing and Commissioning'
- Energy Institute Publication 'Guidance on Meeting Expectations of EI Process Safety Management Framework – Element 13: Operational Readiness and Process Start-up'
- Energy Institute Publication 'Guidelines for the management of integrity of bolted joints for pressurised systems', Second Edition, 2007
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## Relevant HSE Guidance

- HSE Publication Guidance Note GS4, 'Safety requirements for pressure testing', Fourth Edition
- HSE Publication L22, 'Safe use of work equipment, Provision and Use of Work Equipment Regulations 1998 – Approved Code of Practice and Guidance', Fourth Edition, 2014
- HSE Publication L85, 'A guide to the integrity, workplace environment and miscellaneous aspects of the Offshore Installations and Wells (Design and Construction, etc.) Regulations 1996 – Guidance on Regulations', 1996

## Inspection approach

- Review any outstanding punch items and check if their effects on the safety of the plant have been properly assessed. Confirm that there is a plan and a commitment from the duty holder to close outstanding items in a timely manner.
- Check the training records and speak to offshore personnel about the training they have had. Assess if the level of training is suitable for the work being undertaken. Has adequate training been provided for newly installed and commissioned equipment?
- Inspect the records of testing (leak test, functional test) carried out and confirm if any issues were identified. If any issues identified were they adequately resolved?
- Confirm that the extent of any leak test boundary was appropriate for the equipment being tested and where full pressure testing was not carried out that this has been appropriately risk assessed and controlled.

## Matters of Evident Concern

Inspection finding	Examples
Punch list items not closed out	<ul style="list-style-type: none"> <li>• Punch list or equivalent with items appropriately prioritised not available or Duty Holder cannot demonstrate that they have all been addressed.</li> <li>• Duty holder has not assessed the effects of operating without closing out any outstanding punch list items and there is no plan for closing them out.</li> </ul>
Failure to provide training to personnel	<ul style="list-style-type: none"> <li>• New equipment has been installed (or plant changes made) and operations personnel have not been provided with relevant training</li> </ul>
No evidence of commissioning and testing being carried out	<ul style="list-style-type: none"> <li>• Work packs for newly installed equipment are not available or do not include relevant information such as leak test certificates and completed site acceptance testing</li> </ul>

## **APPENDIX 2 – PROCESS PLANT OPERATION WITHIN SAFE LIMITS**

### **Introduction**

All process plant is required to meet particular specifications or ranges of parameters such as throughput, composition of feed and product streams, operating pressure, temperature, energy efficiency etc. The various vessels, pipes, valves, instrumentation and control systems on an offshore installation will be specified in terms of size, materials, layout and operating design in order to meet those requirements, and to ensure safe processing.

Equipment should be designed to be inherently safe, and specified for all foreseeable operating conditions. It is however possible that the process conditions could occasionally exceed the equipment design specification. This could lead to an increased risk of loss of containment of hydrocarbons and subsequent fire and explosion. Examples of this include overpressure of a vessel leading to a burst, or low temperature leading to a brittle fracture. Engineering measures such as relief, blowdown and flare (see appendix 4) or instrumented protective systems (see appendix 3) are typically specified as additional layers of protection to guard against such risks.

In addition, automated process control systems are also applied to the management of process plant. These typically reduce the risk of a hazardous event further still, by reducing the demand rate on the engineered protective systems and ensuring that the plant continues to be operated within its safe limits.

Not all process control operations can be automated however, and there are many activities on a process plant (typically of an intermittent, batch or temporary nature e.g. start-up) which require significant human interaction to perform them. If the failure to perform such tasks correctly or when required could lead to a hazardous event, the task is termed safety critical, and particularly careful assessment and control of those tasks is necessary to ensure safe operation. Personnel required to implement procedures arising from such assessments should be competent to do so, and adequate training, supervision and information about the hazards should be provided, as well as appropriate consideration given to human factors issues.

### **Scope**

This guidance applies to inspection of procedural controls and systems for safe, continuous operation of offshore oil or gas production process plant and pipelines, and protection against loss of containment from them. It includes inspection of such systems whether located on offshore installations or subsea.

It is not intended to cover procedural controls such as those associated with control of work under a permit, isolations, safe reinstatement of plant, management of change or any other topics which are explicitly covered by other appendices of this guide.

## **A) PROCESS PLANT DOCUMENTATION**

### **Fundamental Requirements**

Accurate documentation necessary to support process plant operation within safe limits is identified, maintained up-to-date, and made available to those who need it. Relevant documentation typically includes:

- Process plant design basis
- Asset register of plant items
- Process Flow Diagrams
- Piping and Instrumentation Diagrams (P&IDs)
- Equipment data sheets
- Vendor data sheets and specifications
- Piping specifications
- Instrument data sheets
- Cause and Effect Diagrams
- Hazardous area drawings
- Process plant operating procedures
- Register of alarm and trip settings
- Plant equipment records (inspection and maintenance logs, and records of modifications)
- Incident investigation reports
- Installation integrity registers, e.g. LO / LC valves, PSV, blowdown orifices, SIF etc.

### **Industry Standards and Guidance**

- Energy Institute Publication, 'Guidance on meeting expectations of EI Process Safety management Framework Element 7 - Documentation, records and knowledge management', First Edition, 2014

### **Relevant HSE guidance**

- HSE Publication L22, 'Safe use of work equipment, Provision and Use of Work Equipment Regulations 1998 – Approved Code of Practice and Guidance', Fourth Edition, 2014

### **Inspection Approach**

- Identify what process documentation is held by the duty holder and in which locations, and assess whether this is appropriate.
- Ask offshore staff to show you how they would access/use process documentation relevant to their role, and assess whether there are any problems with doing so.
- Identify the arrangements for the review, maintenance, control, update and issue of the process documentation and assess whether these are sufficient.

- Identify any process plant systems which have been subject to recent modification, and obtain the relevant P&IDs, and where appropriate the associated equipment and instrument data sheets which are held as the controlled copies offshore. Confirm whether the documentation has been updated to reflect the modifications.
- Confirm whether other aspects of the arrangements for control of the documentation are being adhered to (e.g. review periods, transfer of redline mark-ups into permanent revisions, periodic line walking of systems to check accuracy).
- Check for any evidence of inconsistency between the information on controlled documents and other systems. For example:
  - Alarm/trip set points recorded on P&ID and on DCS
  - LO/LC valve designations on P&ID and on valve register
  - Inconsistencies in HP/ LP interface information between registers and P&IDs
  - Pressure safety valve set pressure on P&ID and on valve itself
  - Name of well/slot on P&ID and label on wellhead itself

### Matters of Evident Concern

Inspection finding	Examples
Process plant design basis and specification information is not available	<ul style="list-style-type: none"> <li>• Information has been lost, or not transferred under a change of duty holder.</li> </ul>
P&IDs which accurately reflect the plant configuration are not available	<ul style="list-style-type: none"> <li>• An up to date controlled copy is not available offshore.</li> <li>• P&amp;IDs have not been updated following multiple plant modifications, and /or there isn't an effective process in place for maintaining them.</li> <li>• There is evidence that P&amp;IDs are not used for planning/controlling of plant isolations for maintenance, because they are not trusted by operations staff to be correct.</li> </ul>
There are multiple or significant discrepancies between information in different documentation or systems which relate to ensuring safe operation	<ul style="list-style-type: none"> <li>• Trip settings recorded in process operating procedures are different to those within the ESD system or in proof testing procedures.</li> </ul>

## **B) MANAGEMENT OF SAFE OPERATING LIMITS**

### **Fundamental Requirements**

Safe operating limits (SOLs) for the process plant should be:

- Specified for such parameters as pressure, temperature, level and flow and process composition as may be appropriate, for all parts of the process topsides equipment.
- Recorded such that they are easily accessible to operating staff (e.g. within written instructions, DCS system or other means)
- Maintained in a secure format such that they cannot be modified without appropriate assessment and authorisation
- Regularly reviewed by appropriate technical and operational staff with an understanding of the design basis of the process plant, and the manner by which it is being operated. As well as periodic reviews, reassessment of the limits should be triggered by modifications to the process, whether they be as a result of deliberate changes (e.g. installation of new equipment, tie-ins or wells), or gradual changes to the process conditions (e.g. increasing water cut).

Process plant operation should be monitored with reference to the SOLs. Excursions of operation outside of SOLs should be recorded, investigated, and actions taken to address the root cause and reduce the risk of re-occurrence. Where short term deviations from SOL are required, e.g. low temperatures during gas cap blowdown, then these should be suitably risk assessed and appropriate mitigation put in place prior to taking place.

### **Industry Standards and Guidance**

- Energy Institute Publication, 'Guidance on meeting expectations of EI Process Safety management Framework Element 7 - Documentation, records and knowledge management' First Edition, 2014
- Energy Institute Publication, 'Guidance on meeting expectations of EI Process Safety management Framework Element 9 - Process and operational status monitoring and handover', First Edition, 2014

### **Relevant HSE guidance**

- HSE Publication L22, 'Safe use of work equipment, Provision and Use of Work Equipment Regulations 1998 – Approved Code of Practice and Guidance', Fourth Edition, 2014

### **Inspection approach**

- Identify in what format(s) and location(s) the safe operating limits are held
- Ask control room operators (CROs) to show how they know what the safe operating limits for the process are

- Ask CRO and operators to explain how they detect and correct excursions from SOL
- For a sample set of operating limits on a particular plant item (e.g production separator low levels) ask the CROs to explain:
  - what the limits are
  - why they are set in that way
  - what the consequence of exceeding the limit would be
  - the actions they take to avoid exceeding the limits
  - what actions they would expect any automated systems to take to avoid exceeding the limits
  - what actions they would take if the limits were exceeded
- Ask the process supervisor to explain what actions they take, and systems they use, to ensure that their team is operating the plant within safe limits.
- Assess whether there is an appropriate level of understanding of operations within safe limits by the CROs, and also the right support in place in terms of documentation, procedures, supervision and training to ensure that they can do so.
- Ask the OIM/Ops Supervisor whether their policy on investigation of incidents covers situations where process plant is operated outside of safe limits.
- Ask to see copies of any recent investigation reports which cover such situations
- Ask the CRO/Ops Supervisor/Process Engineer to identify any situations they are aware of where the limits are routinely/occasionally exceeded
- For any such situations/investigation reports, identify what form of reporting, investigation, risk assessment, and mitigation and control has taken place. Has the management of the risk been adequate?

### Matters of Evident Concern

Inspection finding	Examples
Safe operating limits have not been defined or are not readily accessible to operating staff.	<ul style="list-style-type: none"> <li>• P&amp;IDs and operating manuals do not identify safe operating limits for the process plant</li> <li>• There are significant inconsistencies in the limits described in different systems</li> </ul>
Safe operating limits have not been considered/ reviewed as part of a plant modification (or change in process conditions) which may affect them.	<ul style="list-style-type: none"> <li>• New well tieback is added to separator without considering pressure relief requirements</li> <li>• Short term deviations from SOL during certain operating conditions have not been identified or assessed</li> </ul>
There is evidence that process plant is (or has been) operated outside of its safe operating limits, without being reported, investigated and addressed	<ul style="list-style-type: none"> <li>• Wells are started up in a manner that gives rise to risk of flowlines with operating temperature below that of design minimum (risk of brittle fracture)</li> </ul>

## **C) PROCESS OPERATING PROCEDURES**

### **Fundamental Requirements**

Written procedures for the safe operation and use of all process plant equipment on the installation must be provided. They should:

- Be informed by risk assessment of the associated activity or task.
- Be written in accordance with a clear written local standard/format based upon good practice
- Specify the circumstances under which the procedures are to be used (i.e. which procedures apply to which work tasks, and when they should be performed)
- Accurately describe the work equipment, operating conditions, and required work methods, and be based upon on-plant task analysis to inform the step by step content
- Clearly identify the hazards and controls applicable to the equipment, including any critical steps where particular reliance is placed upon people to ensure safety
- Describe the actions to take if foreseeable abnormal conditions occur (including all identified MAH scenarios)
- Be readily available at the point of use, understandable, and in a form designed to maximise usability and minimise error. The level of detail should be appropriate to the task, user and consequence of failure.
- Be regularly reviewed and updated, involving users of the procedures as well as appropriate technical staff. Review should also take place following evidence of non-compliance, or significant incidents where procedural failings or weaknesses have been identified.

Where operating tasks are identified as safety critical, they should be subject to more thorough analysis to ensure that the risks of human error are appropriately assessed. Inspection of this aspect is outside of the scope of this guidance however, and Human Factors specialist input should be sought. Associated operating procedures should reflect the outputs from such studies.

### **Industry Standards and Guidance**

- Energy Institute Publication, 'Guidance on meeting expectations of EI Process Safety management Framework Element 8 - Operating Manuals and Procedures', First Edition, 2014
- Energy Institute Publication, 'Guidance on Human Factors Safety Critical Task Analysis', First Edition, 2011

### **Relevant HSE guidance**

- HSE Publication L22, 'Safe use of work equipment, Provision and Use of Work Equipment Regulations 1998 – Approved Code of Practice and Guidance', Fourth Edition, 2014

- HSE Publication L65, 'Prevention of fire and explosion, and emergency response on offshore installations - Approved Code of Practice and Guidance', Third Edition, 2016
- HSE Publication L70, 'A Guide to the Offshore Installations and Pipelines Works (Management and Administration) Regulations 1995 – Guidance on Regulations', Second Edition, 2002
- HSE Book HSG 48, 'Reducing Error and Influencing Behaviour', Second Edition, 1999
- HSE Human Factors Information Sheet, 'Revitalising Procedures', available at [www.hse.gov.uk/humanfactors/topics/procinfo.pdf](http://www.hse.gov.uk/humanfactors/topics/procinfo.pdf)
- HSE Human Factors Information Sheet, 'HSE Core Topic 4: Reliability and usability of procedures', available at <http://www.hse.gov.uk/humanfactors/topics/core4.pdf>
- COMAH Competent Authority, 'Inspecting Human factors at COMAH Establishments (Operational Delivery Guide)', available at <http://www.hse.gov.uk/comah/guidance/hf-delivery-guide.pdf>

### **Inspection approach**

- Request copy of local standard/procedure(s) governing the format of operating procedures, and arrangements for production, issue, review, update and control.
- Request a list/summary table of all of the operating procedures for the process plant, with an indication of when they were issued/last reviewed and updated/due for review and update.
- Confirm what arrangements are in place for temporary/short term operating procedures. Do these still meet the fundamental requirements and are they sufficiently robust?
- Request copy of operating procedures covering a section of plant of interest (given any duty holder intelligence or other planned inspection topics).
- Assess the suitability of the procedures in line with the fundamental requirements
- Is there evidence that procedures are updated in line with learning from incidents?
- Discuss use of the procedure with process operators. Do they have a good understanding of its requirements? Is the procedure actively referred to/used (particularly for high risk/infrequent tasks)? Do they regard the procedure as easy to use/helpful? Does it reflect how the task is actually performed? Are they involved in a formal review of procedures?

## Matters of Evident Concern

Inspection finding	Examples
Written operating procedures are not in place for some high risk/safety critical tasks	<ul style="list-style-type: none"> <li>• No procedure is in place for an infrequent, high risk task. The risk is increased if the task:-               <ul style="list-style-type: none"> <li>○ involves several steps to perform</li> <li>○ is of long duration (potentially overlapping shifts)</li> <li>○ requires multiple personnel/different disciplines</li> <li>○ is performed by inexperienced staff</li> </ul> </li> </ul>
Operating procedures have multiple inaccuracies or deficiencies which could lead to increased risk	<ul style="list-style-type: none"> <li>• Hazards or pre-requisites for tasks have not been defined</li> <li>• Critical steps in procedures have been omitted</li> <li>• Description of plant equipment or safe limits is incorrect</li> <li>• Procedures cannot be followed, or are difficult to follow</li> </ul>
Operating procedures have not been subject to regular review/update	<ul style="list-style-type: none"> <li>• Procedures have not been reviewed/updated as required following plant modification or organisational change which may require it</li> <li>• Duty Holder does not have a system, or arrangements, in place for conducting regular reviews of the suitability and accuracy of procedures</li> </ul>

## D) PROCESS OPERATOR COMPETENCY

### Fundamental Requirements

Competency standards are set for each process operator role (e.g. Supervisor, CRO, field operators). While they may contain some generic elements, standards should also be installation/role specific, and clearly linked to the MAHs on the installation, and identified responsibilities, tasks and procedures (including safety critical tasks in particular).

Training is well-structured, with a combination of underpinning knowledge/theory and practical experience. It should cover all reasonably foreseeable operating modes, including normal operation, and abnormal/upset, emergency and maintenance conditions.

Trainees have specific training/learning objectives and are allowed sufficient time and support to progress. Trainers and assessors are trained in their roles, and have sufficient experience, knowledge and process understanding to be effective.

Competence is assessed against the standards through an appropriate combination of verbal questioning and written testing of knowledge, witnessing of performance of tasks (practical demonstration or walk through/talk through) and scenarios/table-top exercises. The method of assessment, and recording of evidence to support it, should be proportionate to the criticality of the tasks or hazards and risks concerned.

Arrangements are in place to check and monitor task performance, reassess competence in key areas and provide appropriate refresher training.

### **Industry Standards and Guidance**

- Step Change in Safety Publication, 'Competence Management Framework – Guidance Document', October 2017
- Office of Rail and Road Publication, 'Developing and Maintaining Staff Competence', November 2016

### **Relevant HSE guidance**

- HSE Publication L22, 'Safe use of work equipment, Provision and Use of Work Equipment Regulations 1998 - Approved Code of Practice and Guidance', Fourth Edition, 2014
- HSE Publication L65, 'Prevention of fire and explosion, and emergency response on offshore installations - Approved Code of Practice and Guidance', Third Edition, 2016
- HSE Book HSG 48, 'Reducing Error and Influencing Behaviour', Second Edition, 1999
- HSE Human Factors Information Sheet, 'HSE Core Topic 1: Competence Assurance', available at <http://www.hse.gov.uk/humanfactors/topics/core1.pdf>
- HSE Publication, 'Managing Competence for Safety-Related Systems – Part 1: Key Guidance', available at <http://www.hse.gov.uk/humanfactors/topics/mancomppt1.pdf>
- HSE Publication, 'Managing Competence for Safety-Related Systems – Part 2: Supplementary Material', available at <http://www.hse.gov.uk/humanfactors/topics/mancomppt2.pdf>
- HSE Research Report 086/2003, 'Competence Assessment for the Hazardous Industries', available at <http://www.hse.gov.uk/research/rrpdf/rr086.pdf>

### **Inspection approach**

- Request a copy of procedure(s) governing process operator training and competence assurance.

- Request copies of training/assessment records for process operators expected to be on shift during inspection.
- Request copy of any audit/review of the competency assurance system carried out by (or on behalf of) the duty holder.
- Identify a selection of process operator safety critical tasks, and obtain any associated documentation/procedures.
- Talk to trainers, assessors, and trainees and identify:-
  - how training is structured
  - how assessment takes place
  - whether all operating modes are covered (normal, upsets, emergencies)
  - the arrangements for refresher training and re-assessment where appropriate
  - how the trainers/assessors are appointed
- Assess whether the arrangements are sufficiently robust.
- Assess documentation and records for individuals. Are these sufficient?
- Question operators on their understanding of the selected safety critical tasks. Do they demonstrate a good understanding of the hazards, their key responsibilities and required actions?
- Identify the arrangements for auditing of the effectiveness of the training and competence assurance systems. Are these sufficient?

### Matters of Evident Concern

Inspection finding	Examples
Arrangements for training are weak	<ul style="list-style-type: none"> <li>• Operators are required to train themselves by working alongside experienced operators, without any structured support</li> <li>• Training for process upsets and/or MAH scenarios has not been provided</li> <li>• An appropriate refresher training programme is not in place for safety critical tasks</li> </ul>
An effective competency management system is not in place for process operators	<ul style="list-style-type: none"> <li>• Operators have responsibility for carrying out safety critical tasks, without having evidence to demonstrate that they been assessed as competent to do so</li> <li>• Operator competency standards, specific to the installation and its hazards and procedures, have not been defined.</li> </ul>

## **E) PROCESS OPERATOR SHIFT/CREW CHANGE HANDOVERS**

### **Fundamental Requirements**

Duty holders should have arrangements in place to ensure effective process operator handover including:-

- A procedure which specifies the requirements for handover
- Allocation of sufficient time for individuals to prepare and deliver handovers
- Specification of the information that must be handed over, which is expected to include (but not limited to):
  - a summary of current operational status
  - any planned or on-going work activities
  - changes in procedures (temporary or permanent)
  - new operational risk assessments
  - changes in equipment in/out of service
  - over-rides of safety system
- Provision of structured, written logs, to support verbal communication (with sections to record safety-critical information);
- Arrangements to ensure that key information is transmitted both verbally and in writing, encouraging two way communications etc.
- Arrangements to ensure distraction during handovers is minimised
- Arrangements to ensure crosschecking of information transmitted/received at handovers via other staff within the team
- Arrangements to ensure face-to-face communication where reasonably practicable
- Arrangements to develop and maintain staff competence in handovers, including communication and non-technical skills (e.g. active listening; two-way communication with repetition and feedback; radio protocols)
- Arrangements to monitor, audit and review implementation of handover arrangements

### **Industry Standards and Guidance**

- Energy Institute Publication, 'Guidance on meeting expectations of EI Process Safety management Framework Element 9 - Process and operational status monitoring and handover', First Edition, 2014

### **Relevant HSE guidance**

- HSE Book HSG 48, 'Reducing Error and Influencing Behaviour', Second Edition, 1999
- HSE website guidance, 'Human Factors: Shift Handover', available at <http://www.hse.gov.uk/humanfactors/topics/shift-handover.htm>

### **Inspection approach**

- Request copy of procedure(s) governing process operator handovers

- Request copies of any documentation/logs/templates used to support handovers
- Observe a number of 'live' handovers between CROs, outside operators, process supervisors etc. This should be for a range of different types of handover (including shift change/crew change) where possible. This may require a coordinated approach with other inspectors, as handovers for different roles are likely to take place at similar times
- Test the understanding of the incoming personnel of the transferred information, including plant status/hazards and priorities for action, and cross check this with other observers/handovers.
- Assess the quality of the procedure and the effectiveness of the observed handovers against the fundamental requirements
- Identify whether systems for training and competence assessment of handovers (or supporting communication skills) are in place and effective
- Identify what arrangements are in place for monitoring, audit and review of handovers

### Matters of Evident Concern

Inspection finding	Examples
Handovers are ineffective	<ul style="list-style-type: none"> <li>• Handovers are verbal only</li> <li>• Systemic evidence of critical information being missed/not handed over effectively</li> <li>• Significant impediments to effective handover exist (e.g. time pressure, distractions)</li> </ul>
Procedural controls for handovers are lacking	<ul style="list-style-type: none"> <li>• No procedure, documentation/templates or other guidance on format/content/style of handovers is in place</li> <li>• No arrangements are in place for training and competence assessment in delivery of handovers (or supporting skills)</li> </ul>
Ineffective monitoring/audit/review or handovers is in place	<ul style="list-style-type: none"> <li>• No arrangements are in place to supervise and monitor the effectiveness of handovers, and take action where required.</li> </ul>

## F) SUPERVISION OF PROCESS OPERATIONS

### Introduction

The role of a supervisor is to lead their team, ensuring that the necessary work is planned and allocated amongst its members, and monitoring performance and compliance to ensure it is carried out correctly, and in a safe and efficient manner.

In doing the above, supervisors will need to make decisions, and take actions, which affect members of the team and the delivery of the work which will have an impact on health and safety. Crucially, supervisors can have a significant, positive impact on a range of local performance influencing factors (compliance with procedures, training and competence, safety-critical communication, staffing levels and workload, shift work and fatigue, organisational culture etc.)

Poor supervision is believed to have contributed to a number of major accidents (Texas City, Texaco Milford Haven, Hickson and Welch, Piper Alpha)

## **Scope**

This guidance applies to inspection of direct line supervision of the production operations team offshore.

## **Fundamental Requirements**

In performing their role, supervisors need to know what is expected from them in terms of health and safety. They need to understand the duty holder health and safety policy, and their part in it. In particular they need to know and understand the specific hazards of the equipment and processes that their team operates, and the procedures, controls and arrangements which are required to be adopted in order to control the associated risks.

Supervisors need to understand their teams, and individual team members' capabilities, attitudes and motivations in order to lead them effectively; address any development needs; and ensure effective involvement, engagement and delivery, both individually and collectively.

The supervisor's role must be suitably designed, such that individuals have sufficient resources, time and opportunity to interact with others in order to fulfil their supervisory responsibilities. Problems can emerge because of poorly defined responsibilities, heavy workloads, inadequate resources, and/or inadequate management or technical support.

Supervisors should take the lead during unusual or higher risk activities, and emergency events. The duty holder should have in place arrangements describing the role of supervisors, which address the requirements and attributes above. This should include:

- Management philosophy and strategy
- Job descriptions
- Training and competency arrangements for supervisors
- Mentoring arrangements for new supervisors
- Emergency response

Arrangements should be in place to measure, audit and review all aspects of supervisory performance

### Industry Standards and Guidance

- Energy Institute Publication, 'Human Factors briefing Note No 21 – Supervision'

### Relevant HSE Guidance

- HSE Publication OTO 0065/1999, 'Effective supervisory safety leadership behaviours in offshore oil and gas industry'
- HSE Publication HSG65, 'Managing for health and safety', Third Edition, 2013

### Inspection Approach

- Request job descriptions and competency frameworks for production/operations team leaders and supervisors and assess for suitability.
- Interview line manager, supervisors and team members to gain an understanding of the performance of supervisors

### Matters of Evident Concern

Inspection Finding	Examples
No clear supervisory competency system	<ul style="list-style-type: none"> <li>• No training or competency arrangements for developing personnel as supervisors.</li> </ul>
Individual supervisors lack sufficient competency, and additional support is not in place to mitigate any gaps	<ul style="list-style-type: none"> <li>• Supervisors have a poor understanding of the process plant and its procedures.</li> <li>• Supervisors have not completed identified emergency response training</li> </ul>
Supervisors not available to team	<ul style="list-style-type: none"> <li>• Too much time spent in meetings and on administrative tasks. Too little time spend on plant/control room.</li> </ul>
Poor planning and supervision	<ul style="list-style-type: none"> <li>• Tasks are not carried out in a timely manner. Activities are often handed over to the next shift.</li> <li>• The operations team are not aware of the work they are required to do</li> </ul>

## **APPENDIX 3 – INSTRUMENTED PROTECTION SYSTEMS**

### **Introduction**

Instrumented Protection Systems (IPSs) are often employed to provide protection against vessels or lines being subjected to over-pressures, over-fill, low temperature excursions or other forms of IPS which provide or contribute to protection against loss of containment events. Typically such systems will be used in combination with other forms of protection such as mechanical pressure relief valves. However in some cases an IPS provides the sole means of protection. Whatever the duty, an IPS will typically comprise a sensor or sensors, logic solve and end element to protect against the unsafe condition. Good practice is for an IPS not to require any operator response for its normal operation.

Other forms of IPS which provide or contribute to protection against loss of containment may be encountered. IPS's may also be referred to as Safety Instrumented Systems (SIS), Safety Instrumented Function (SIF), High Integrity Pressure Protection Systems (HIPPS), Trips, Interlocks, or Instrument Based Protective Systems.

Alarms may be provided to alert operators that process variables are reaching the limits of normal operation, thereby providing the opportunity for operators to make corrections to the operation of the plant before an IPS trip level is reached. Alarms are typically implemented in the plant process control system and so are not subject to the same requirements as an IPS.

### **Scope**

This inspection guidance applies to Instrumented Protection Systems providing, in part or in whole, protection against loss of containment from offshore oil or gas topsides equipment and pipelines. This section will not cover Fire and Gas systems (detection, active fire protection systems or shutdown from F&G systems).

## A) SAFETY INSTRUMENTED SYSTEMS

### Fundamental Requirements

Most plants in the process industry handling dangerous substances rely on safety instrumented systems (SIS) to ensure that accident risks are tolerable. IEC61508 provides guidance on the design and operation of SIS to ensure an adequate reliability in service, supported by guidance for the process sector in IEC61511. A SIS is designed to carry out specific functions as part of a Safety Instrumented Function (SIF).

**NB:** IPS/ SIS/ SIF are used interchangeably within this document but all should be taken to refer to specific instrumented protective loops which provide a safety function. Other protective loops may be provided for environmental or business critical reasons but they are out with the scope of this guide.

The two widely used methods in the Oil and Gas industry for integrity level determination are Layer of Protection Analysis (LOPA) and Risk Graphs. Each of these methods has their own advantages and disadvantages. LOPA allows the required risk reduction to be incorporated into the SIL values with higher precision. This enables a more detailed consideration of the available protection layers and leaves an objective traceable record of the decision-making process. In contrast, the simplicity of Risk Graphs makes them convenient for screening a large number of SIFs. This can make Risk Graphs useful as a first screening pass prior to using LOPA. However, Risk Graphs are still widely used as a stand-alone method. All SIFs should be designated as a safety critical and environmental element (SECE). SILs are designated as SIL 0/1/2/3/4, with SIL 4 being the most onerous and highly unlikely to be encountered in industry. SIL 0 is a system with a low integrity requirement and therefore not SIL rated. Most SIFs on a process plant would be designated as a SIL 1 or a SIL2. Higher SIL rated systems are often associated with HIPPS.

IEC61508 and IEC61511 require that there should be a Functional Safety Assessment (FSA) for all SIL rated SIFs. The FSA should be carried out by a team including the technical and operations expertise for the installation being inspected and should include at least one senior competent person not involved in the project design team. It should provide a judgement as to the functional safety and safety integrity achieved by the SIFs. SIFs which have been commissioned prior to the publication of the relevant standards may not have an FSA.

The Duty Holder should be asked to demonstrate that proof test procedures are in place for every SIF and that there is evidence that the procedures have been carried out. The procedures should ensure that all elements (including all elements in redundant configurations) of a SIF are periodically tested at a frequency as specified by the SIF designer. The procedures should provide clear instructions and should ensure that all critical aspects of performance

(eg closing time of a fast acting HIPPS valve) are tested so that any faults which are not apparent during normal operation are revealed.

It should be noted that not all installations (usually older installations) use the SIL approach and adopt the methods set out in API 14C. API 14C details the protective systems and equipment which should be associated with standard offshore equipment (as well as safety check-lists for that equipment), i.e. separators, pumps etc. API 14C also states that the safety system should provide two levels of independent protection to minimise the effect of equipment failure for the process. The protective equipment should still be subject to frequent inspection such that the safety equipment operates on demand. All protective equipment should be designated as a safety critical and environmental element (SECE).

### **Industry Standards and Guidance**

- BS EN 61508: 2010 'Functional safety of electrical/electronic/programmable electronic safety related systems'
- BS EN 61511: 2017 'Functional safety – Safety instrumented systems for the process industry sector'

### **Relevant HSE guidance**

- SPC/Tech/OSD/31 Safety instrumented systems for the overpressure protection of pipeline risers
- HSE Publication L22, 'Safe use of work equipment, Provision and Use of Work Equipment Regulations 1998 - Approved Code of Practice and Guidance', Fourth Edition, 2014
- HSE Publication L65, 'Prevention of fire and explosion, and emergency response on offshore installations - Approved Code of Practice and Guidance', Third Edition, 2016
- HSE Publication, 'Managing Competence for Safety-Related Systems – Part 1: Key Guidance',  
<http://www.hse.gov.uk/humanfactors/topics/mancomppt1.pdf>
- HSE Publication, 'Managing Competence for Safety-Related Systems – Part 2: Supplementary Material',  
<http://www.hse.gov.uk/humanfactors/topics/mancomppt2.pdf>

### **Inspection Approach**

- Verify that all SIFs are declared as a SECE in the relevant performance standards and have appropriate testing frequency assigned.
- Where a duty holder utilises SIL levels on an installation, Identify SIFs from the P&IDs and ensure that the function has a SIL rating calculation associated with it.
- Where a duty holder utilises API14C for the plant safety systems, verify that a company standard is in place which describes the installed safety systems.

- Verify that an FSA in accordance with IEC 61508 or IEC 61511 has been carried out for any IPS. A competent FSA will provide evidence that the IPS(s) have been specified, designed, installed and commissioned in line with the relevant standards.
- Ensure that all elements of the SIF are being inspected at suitable intervals and that the results of the inspection are being appropriately recorded. Typical inspection records should include; any tools which were required to carry out the work (and its calibration date if necessary), alarm and trip activated set-points as part of the instrument testing, valve opening and/or closing times, faults detected as part of the testing and who carried out the inspection (including date).
- Verify that procedures used for carrying out proof testing activities on safety critical elements are suitable for the task to be carried out. Generic templates may be used providing that they accurately reflect the task to be carried out.
- Inspection of maintenance records to ensure that the process elements of the SIF are being maintained on a regular basis such that the safety related features are functioning correctly and on demand (as specified in the SIL functional assessment).
- Duty holder should have arrangements in place for control of all SIF software and configuration settings (i.e. cause and effect logic, alarm and trip settings and system software). There should be effective change control procedures, requiring appropriate authorisation for all changes and evidence of the management of change.
- Verify whether or not short term deviations from SOL are taking place and how these are being managed.
- Review the training records, experience and certification of the technicians or operators carrying out the work on SIFs to ensure that they are competent to do so.

### Matters of Evident Concern

Inspection finding	Examples
Safety Integrity Levels of SIFs are not available onshore.	<ul style="list-style-type: none"> <li>• Information with regards to SIL or criticality of SIFs are not available onshore.</li> <li>• A SIL assessment has not been carried out on a SIF.</li> <li>• Where it is not practicable for a SIL assessment to be carried out (e.g. older installed equipment), the duty holder has not performed a Gap analysis of safety related requirements.</li> </ul>
Inspection/Maintenance records are not available offshore for safety critical equipment forming part of the SIF.	<ul style="list-style-type: none"> <li>• Instrument, valves or other end elements not captured in maintenance management system.</li> </ul>

Inspection finding	Examples
Supervisors, Technicians or Operators cannot demonstrate competence to carry out work on SIFs	<ul style="list-style-type: none"> <li>• Information with regards to training courses, installation experience and O&amp;G experience is not available offshore.</li> <li>• Information with regards to training etc is either kept onshore or by a third party contractor.</li> </ul>
No processes for changing alarm and/or trip settings.	<ul style="list-style-type: none"> <li>• No process in place for management or altering alarm/trip settings.</li> <li>• Ability to change alarm/trip settings in the DCS without any management of change process.</li> </ul>
Alarm and/or trip settings are not available offshore.	<ul style="list-style-type: none"> <li>• Information should be available offshore, which could be in a separate register (paper or electronic) or as part of the maintenance management system.</li> <li>• Information may be available onshore but not offshore.</li> </ul>

## B) ALARM MANAGEMENT

### Fundamental Requirements

EEMUA 191 provides industry guidance on the design, development, procurement, operation, maintenance and management of alarm systems. The guidance states that the key design principles for an alarm system are that:

- Each alarm should alert, inform and guide the operator,
- Each alarm presented to the operator should be useful and relevant,
- Each alarm should have a defined response with adequate time for that operator to carry out the response,
- The alarm should be designed to take account of human limitations.

The duty holder should have an alarm management strategy which takes in to account the guidance set out in EEMUA 191 or BS EN 62682. Where installations were designed prior to introduction of EEMUA 191 or BS EN 62682 and have not upgraded their control system it is still expected that they should follow the underlying principles for alarm management. Acceptable alarm rates within these documents are marginally different however both are considered acceptable targets.

EEMUA 191 states that a long term average alarm rate (in steady state operation) of less than 1 per 10 minutes is very likely to be acceptable. One alarm per 5 minutes is deemed as manageable, but 1 per 2 minutes is likely to be over-demanding and more than 1 per minute is likely to be unacceptable.

Following a major plant upset, under 10 alarms displayed in the 10 minutes following the upset should be manageable by the operator, with 20-100 hard for the operator to cope with and more than 100 defined as definitely excessive.

Operators may need to suppress alarms at times, for instance when areas of the plant are shutdown with a number of standing alarms. The duty holder should have guidance in place for operator suppression of alarms.

Often, operator response to alarms is captured within a SIL assessment as a risk reduction factor. EEMUA 191 sets out the following guidance for the claimed  $PFD_{avg}$  of the alarm safety function:

- $PFD_{avg}$  1-0.1 (standard alarm) – alarm and final element to be integrated into process control system (PCS) with no special requirements other than to consider good alarm design and management.
- $PFD_{avg}$  0.1-0.01 (safety critical alarm) – alarm and final element systems should be designated as safety critical and categorised as implementing SIL 1 functions. Alarm and final element systems should be separate from the PCS. The alarm should be designated as high priority and remain on view to the operator at all times while activated. The operator should be trained in the management of the specific plant failure that the alarm indicates. The claimed operator performance should be audited and the response time should be less than the time taken to reach an unsafe condition, i.e. time from alarm initiation to unsafe condition occurring.
- $PFD_{avg} < 0.01$  – alarm and final element systems should be designated as safety critical and categorised as implementing SIL 2 functions. EEMUA recommends that claims for a  $PFD_{avg}$  below 0.01 are not made for any safety function which requires operator action.

Alarm and trip settings should be recorded by the duty holder, available offshore and have an appropriate system in place for managing and changing these settings. Where credit is taken in the integrity level assessment for operator response to an alarm, this should be tested offshore.

### **Industry Standards and Guidance**

- EEMUA191, 'Alarm Systems – A Guide to Design, Management and Procurement', Third Edition, 2016.
- BS EN 62682:2015, 'Management of alarms systems for the process industries'

### **Relevant HSE guidance**

- HSE Publication L22, 'Safe use of work equipment, Provision and Use of Work Equipment Regulations 1998 – Approved Code of Practice and Guidance', Fourth Edition, 2014

- HSE Publication L65, 'Prevention of fire and explosion, and emergency response on offshore installations - Approved Code of Practice and Guidance', Third Edition, 2016
- HSE Publication, 'HSE Human Factors Briefing Note No. 9 – Alarm Handling', available at <http://www.hse.gov.uk/humanfactors/topics/09alarms.pdf>
- HSE Contract Research Report 166/1998, 'The Management of alarm systems', available at [http://www.hse.gov.uk/research/crr\\_pdf/1998/crr98166.pdf](http://www.hse.gov.uk/research/crr_pdf/1998/crr98166.pdf)

### Inspection Approach

- Verify that the duty holder has an alarm design and management strategy that takes in to account industry standards such as EEMUA 191 – Guide to Alarm System Management and Procurement.
- Verify that where a duty holder has claimed a  $PFD_{avg}$  of less than 0.1 for an operator response to an alarm as part of the SIL rating of a SIF that this is being appropriately audited by the duty holder in line with EEMUA 191 guidance.
- Review the number of incoming alarms whilst in the control room under normal operating conditions and confirm with the control room operator that this is normal.
- Review the number of standing alarms in the control room and confirm the origin of these alarms.
- Where the control room operator can shelve alarms, verify that the duty holder has a process or procedure in place for allowing them to do so.
- Where there are an unacceptable number of incoming and/or standing alarms, confirm that the duty holder has a plan in place for prioritising and reducing these alarms to a manageable number. Any alarm reduction strategy should take into account the normal duties of the CRO.
- Verify that the duty holder has a process in place for updating and managing the alarm and trip settings on their installations.

### Matters of Evident Concern

Inspection finding	Examples
Duty holder claims a $PFD_{avg}$ of less than 0.1 for an operator response to an alarm as part of SIL rating of a SIF.	<ul style="list-style-type: none"> <li>• Duty holder not appropriately auditing operator response to alarm.</li> <li>• Alarm is not designated as being safety critical.</li> <li>• Alarm is not separate from the PCS.</li> <li>• Alarm is not prioritised on the DCS.</li> </ul>
CRO not able to handle alarms displayed at HMI.	<ul style="list-style-type: none"> <li>• Too many nuisance alarms in the control room.</li> <li>• Too many standing alarms which detract from incoming alarms.</li> <li>• Shut-down or redundant equipment with alarms which are still connected to the DCS.</li> </ul>

Inspection finding	Examples
Alarms are not prioritised on the HMI.	<ul style="list-style-type: none"> <li>• No safety critical alarms on the installation.</li> <li>• Non-safety critical alarms may detract from safety critical or high priority alarms.</li> <li>• Software does not allow for critical alarms to be prioritised.</li> </ul>
Alarms are constantly accepted and reset at HMI without any review or understanding.	<ul style="list-style-type: none"> <li>• CRO shelves incoming alarms without investigation or explanation of why alarm was shelved.</li> <li>• No time limit for shelved alarms (i.e. re-activation of shelved alarm after 15minutes).</li> </ul>
Alarm and trip settings are unavailable.	<ul style="list-style-type: none"> <li>• Duty holder does not have an alarm and trip settings register (paper or electronic).</li> <li>• Alarm and trip settings are unavailable offshore.</li> <li>• Alarm and trip settings are available as a paper copy but not been updated or subject to management of change.</li> <li>• Duty holder has no process in place for updating alarm or trip settings.</li> <li>• Alarm and trip settings tested as part of proof or maintenance tests do not match those of the alarm and trip register.</li> </ul>
Alarm response of operator not tested as part of SIF.	<ul style="list-style-type: none"> <li>• Integrity level review has included operator response to an alarm as part of SIF for risk reduction but not tested as part of SIF.</li> </ul>

## C) OVER-RIDES AND INHIBITS

### Fundamental Requirements

Overrides can be placed for several reasons during operations; start-up, routine operations (i.e. sampling), commissioning, decommissioning, maintenance and potential adverse conditions. There are normally three types of override; input (i.e. on a sensor which initiates a shutdown event), output (within the logic of the shutdown system or at the final element) and inter-trip (disabling the shutdown functionality). Output and inter-trip overrides require special attention as they can have multiple initiating actors that require the operation of a final element. Application of multiple inhibits on the same system also requires special attention to address possible loss of protective

layers and if the plant has sufficient protection to safely shut down on demand if required.

The duty holder should have an overrides strategy which typically details the following issues:

- The level of authorisation which is required for an override. Instrumentation deemed as safety critical should require a higher level of authorisation than instrumentation which is not deemed safety critical.
- The time an override can be active for and the level of assessment and authorisation required for the increased length in time.
- Levels of authorisation and considerations of multiple overrides, i.e. cumulative risk assessment.
- The level of risk assessment required prior to applying an override or inhibit (and who should be involved). This may include an ORA if an override is to be active for a prolonged period of time.
- The roles and responsibilities of onshore and offshore personnel.
- Shift hand-over operations to ensure on-coming CROs are aware of any active overrides.
- Onshore and offshore audit requirements of applied overrides.

In older plant where key override switches are used, it should be ensured that the keys are under appropriate control and supervision. Any keys which are actively placed in override panels should be accounted for in the same way that an electronic override is placed.

The CRO should be aware of all applied overrides on the plant and should be able to explain what other plant protective devices are in place to ensure that the plant could safely shut down on demand if required.

### **Industry Standards and Guidance**

- BS EN 61511: 2017 'Functional safety – Safety instrumented systems for the process industry sector'

### **Relevant HSE guidance**

- HSE Publication L22, 'Safe use of work equipment, Provision and Use of Work Equipment Regulations 1998 - Approved Code of Practice and Guidance', Fourth Edition, 2014
- HSE Publication L65, 'Prevention of fire and explosion, and emergency response on offshore installations - Approved Code of Practice and Guidance', Third Edition, 2016

### **Inspection approaches**

- Verify that the duty holder has a procedure in place for the application of overrides.

- Confirm that the duty holder has a process in place for application of overrides in terms of time period, criticality and authorisation required.
- Confirm that long term safety critical overrides on the installation are accompanied by an ORA and that strategies are in place for removing.
- Confirm that overrides of safety critical equipment have a risk assessment in place.
- Review all areas of the installation where overrides can be placed and verify that the procedure is being followed. Verify which personnel are authorised to place overrides at remote terminals or panels. Ensure that the control room operator is aware of all process related overrides applied.
- Review the paperwork associated with the overrides (both currently applied and historic). These may include permit for the work, risk assessment for the override, control room operator daily log, override logs. These could either be paper or electronic?
- Confirm that the control room operator is aware of other plant protective devices, other monitoring requirements, required actions, and their associated criticality to allow shutdown the plant in an emergency situation whilst overrides are applied.
- Verify that regular and frequent audits of applied overrides are being carried out from both onshore and offshore teams. Confirm that the duty holder produces results and potential improvements from the audit results. Audits should also include checking that the controls and mitigations used as part of the override are appropriate and are being applied.

### Matters of Evident Concern

Inspection finding	Examples
Overrides and Inhibits are applied without risk assessment or appropriate approval.	<ul style="list-style-type: none"> <li>• No procedure or process in place for application of overrides.</li> <li>• Procedures or processes for application of overrides are not being followed on the installation.</li> <li>• No formal risk assessment process in place for assessment of overrides.</li> <li>• ORAs not applied for long term overrides and no strategy to remove long term overrides</li> <li>• Risk assessments normally not raised for short term procedural overrides.</li> <li>• Risk assessments not raised for short term maintenance activities associated with safety critical elements.</li> </ul>
ESD overrides applied for greater than one shift.	<ul style="list-style-type: none"> <li>• No procedure or assessment process in place for application of overrides.</li> <li>• Procedures or processes for application of overrides are not being followed on the installation.</li> </ul>

Inspection finding	Examples
Overrides and Inhibits applied remotely.	<ul style="list-style-type: none"> <li>• Overrides applied by technicians or operators at remote panels or HMIs without CRO knowledge or appropriate authorisation or assessment.</li> </ul>
Keys used for ESD overrides remain in panels (when not used).	<ul style="list-style-type: none"> <li>• No processes or procedure in place for management of keys.</li> <li>• No control or appropriate authorisation of keys for application of overrides.</li> </ul>
Override applications not being audited.	<ul style="list-style-type: none"> <li>• Processes not in place for offshore or onshore auditing.</li> <li>• Procedure not being followed for onshore or offshore auditing.</li> <li>• No reporting of onshore or offshore audits of applied overrides.</li> </ul>

## **APPENDIX 4 - RELIEF, BLOWDOWN, VENT AND FLARE SYSTEMS**

### **Fundamental Requirements**

The duty holder should have in place arrangements to prevent over- and under-pressure of process plant and equipment. Such extremes may lead to a rapid and uncontrolled loss of containment event. Pressure systems should ideally therefore be designed for maximum and, where relevant, the minimum anticipated operating pressure under all modes of operation. It needs to be borne in mind that the maximum operating pressure may not occur during the normal mode of operation.

Designing equipment and systems to the maximum pressure (or vacuum) to which it can be subjected can have advantages in simplifying plant by reducing or eliminating protection or relief systems. Where necessary, facilities should be protected with recognised relief devices discharging to suitable disposal or an instrumented high integrity protection system or a combination of both. All possible sources of overpressure need to be identified and allowed for.

A means of removing significant hydrocarbon inventories from equipment to a safe location should also be provided (blow-down). This can be used immediately following detection of a loss of containment, or pre-emptively if there is a risk of an adverse situation escalating in consequence.

Hydrocarbons arising from relief and blow-down events need to be safely conveyed to atmospheric vents or a flare for effective dispersion and disposal. The vent and flare system must be capable of handling credible combinations of upstream events, without compromising the ability of the protective devices to prevent over-pressure. The vent and flare systems must also not introduce other hazards such as excessive thermal radiation, or the potential to generate flammable mixtures within pipework.

The following sections describe in more detail the expected elements of control that are required.

### **Relief and Blow-down system design and philosophy**

- Relief device designs are documented, with assumptions on required relief rates, fluid conditions, and design methods/codes clearly recorded.
- Relief stream piping routes and sizing are assessed to ensure that the ability of the devices to prevent overpressure of upstream equipment is not compromised under all credible cases
- Incompatible fluids are segregated (e.g. cold streams / wet streams, or hot streams / condensate). Piping is designed to prevent slugs of liquid accumulating
- Relief stream designs are re-assessed in light of changing process conditions and duties to ensure they remain fit for purpose
- Where blow-down systems cannot handle simultaneous flow from all protected systems, suitably robust controls are put in place to enable

phased operation or ESD system configured to initiated staggered blowdown.

- Knock out drums should be sized to manage foreseeable relief events.
- The design of the relief and blow-down systems should be re-evaluated in the light of any additions of new equipment or changed operating conditions (e.g. well fluid composition change).

### **Relief and Blow-down operation**

- Operating procedures should be in place for the relief and blow-down system, which specify routine checks of purge rates and that header drains (where installed) are clear.
- Operating procedures or guidance should be in place to identify under what circumstances it is safe to continue operating or whether a shutdown should be initiated. Note that there may be instances where a plant shutdown without blowdown is the safer approach, e.g. rupture in flare header, such a situation should be clearly documented.
- The flare drum should be capable of performing its relief function when a high liquid level is present and without compromising gas/ liquid separation. Where flare drum performance is impacted by a high liquid level then a suitable response plan should be in place.
- Routine tests should be performed on the operation of blow-down systems to confirm their effectiveness (time to depressurise, excessive vibration etc) under a controlled (non-emergency) situation.
- The Duty Holder should have a system in place for recording and assessing blowdown events out with planned testing including identification of any parts of the blowdown system which fails to meet the required Performance Standard.
- A policy should be in place regarding the need for (or otherwise) of relief valve/pipework testing/overhaul following operation of a relief or blow-down system. Relief stream operation may lead to impairments to the relief stream components, such as bursting disc failure, relief valve seat damage, blockage/fouling. The likelihood of such damage will depend on the process system and fluids involved, as well as the design of the stream and the duration of the release.
- The Duty Holder should have a maintenance strategy in place for routine testing / replacement of relief devices and also a system for retention of test records for audit purposes. A register of relief devices should also be maintained and contain critical information such as, but not be limited to, sizing basis, set-pressure and minimum required orifice size. Where bursting discs are used as relief devices then bursting disc-type (forward/ reverse acting) and minimum / maximum allowable burst pressures should be recorded.
- Where isolation valves are installed downstream of relief or blowdown devices, the Duty Holder should have suitable arrangements in place to prevent inadvertent closure of these isolation valves while the relief / blowdown device is in service. Suitable arrangements include key-interlock systems or as a minimum a robust system for locked open / locked closed

valve control. Change in isolation valve position shall only be carried out following suitable risk assessment.

### **Flare operation**

- Arrangements (typically a nitrogen or fuel gas purge) should be in place to ensure that air ingress to the flare headers, leading to the formation of a flammable mixture, cannot occur. This should function under all installation conditions (particularly during start-up and shutdown where a source of fuel gas may not be available).
- Flare header drains need to be clear and not choked with debris, and rates of purge gas (if used) above safe minimum requirements. Both should be subject to regular operator checks
- Following a platform shutdown which results in extinguishing of the flare, operating procedures should provide guidance as to how the flare shall be ignited. The procedures should provide guidance on minimum purge rate (fuel gas or nitrogen) and duration of purge to ensure that the flare header (knock-out drum to tip) is purged of air prior to ignition.
- Operating procedures for ignition of the flare must also give consideration to the impacts of venting unignited gas taking into account atmospheric conditions (wind speed and direction) and the results of any gas dispersion analysis that has been undertaken. Venting of unignited gas from the flare for an extended period should not take place.
- A safe means of lighting the flare must be in place with the preference being an engineered ignition system (auto-ignition or manual). Where an ignition system is not installed or is unavailable then an alternative safe means for lighting the flare must be provided. A method of ensuring that the flare stack contents and any pilot systems are outside of the flammable mixture region to prevent flashback during lighting is required.
- Thermal radiation from the flare must not risk damage to personnel, through direct contact, or through knock damage to other installation equipment (including safety critical elements in particular)
- Toxic components within gases that are flared must be effectively destroyed, and the combustion products sufficiently dispersed so as not to risk harm to personnel.
- Where cold (atmospheric) vents are used in place of conventional flare (typically on unmanned installations) then the Duty Holder shall have carried out a gas dispersion analysis to ensure that cold venting of gas poses no risk to the installation. Cold vents should be provided with suitable flame arrestors (or alternative) to prevent flash-back in the event of unintended ignition with maintenance procedures in place to ensure that the arrestors do not become blocked or restricted.

### **HP/LP interface studies**

- Risks of over-pressurisation at HP/LP interfaces must be identified, assessed, and controlled.
- Protection may be by mechanical relief or instrumented trips of adequate integrity. In some situations it may be by procedural or other means to

prevent over-pressurisation, using locked valves, blinds, restrictor orifices etc. It is generally best to carry out a specific HP/LP interface study, separate from the more routine HAZOP procedure.

### **Industry Standards and Guidance**

- API Standard 520, 'Sizing, Selection, and Installation of Pressure-relieving Devices : Part I – Sizing and Selection', Ninth Edition, 2014
- API Standard 520, 'Sizing, Selection, and Installation of Pressure-relieving Devices : Part II – Installation', Sixth Edition, 2015
- API Standard 521, 'Pressure-relieving and Depressuring Systems', Sixth Edition, 2014
- API Standard 526, 'Flanged Steel Pressure-Relief Valves', Seventh Edition, 2017
- BS EN ISO 23251, 'Petroleum, petrochemical and natural gas industries – Pressure-relieving and depressuring systems', 2008
- BS EN ISO 4126, 'Safety devices for protection against excessive pressure', Various
- Energy Institute Publication, 'Guidelines for the safe and optimum design of hydrocarbon pressure relief and blowdown systems', 2001

### **Relevant HSE Guidance**

- HSE Publication L65, 'Prevention of fire and explosion, and emergency response on offshore installations - Approved Code of Practice and Guidance', Third Edition, 2016

### **Inspection Approach**

- Request a copy of the installation relief and blowdown study and a copy of the Performance Standard associated with the flare / pressure relief system. Verify that the flare system design performance and associated performance standard are in line with the recognised standards or where it does not comply that a suitable demonstration has been made for a less onerous performance.
- Where high pressure gas systems are installed, verify that the impact of low temperature downstream of relief devices has been considered and that the system is suitably design, i.e. correct material specification.
- Request the duty holder to provide a copy of historical blowdown tests (planned or unplanned) and confirm that the system is performing as per the design requirements. Where the system is not performing as per design then ensure that a suitable and sufficient risk assessment / ORA is in place demonstrating that it is safe to continue operating with an impaired flare system.
- Request the Duty Holder to demonstrate how they identify and assess unplanned blowdown events.
- Request a copy of the Duty Holder maintenance strategy / inspection frequency for relief devices. Verify that there is no outstanding

maintenance / inspection of relief devices or where present that a sufficient risk assessment has been carried out to justify continued operation.

- Select a sample of relief devices on the installation and request copies of maintenance records including test certification and verify that maintenance is being carried out at the identified frequency.
- Inspect a sample of relief devices in-field and confirm that they are suitably tagged, name plate details reflect test certification, e.g. serial number and set-pressure, and that where isolation valves are installed that they are suitably secured in the correct position.
- Request a copy of the flare radiation and gas dispersion assessment for the installation. Determine whether there is any risk from thermal radiation or dispersion of unignited gas, e.g. touch down on process deck.
- Review the operating procedure for the flare system and confirm that it provides sufficient guidance in relation to safe operation of the flare. In particular, consider the guidance provided on minimum flare purge, precautions for start-up and any weather related provisions (gas dispersion impacts).
- Verify that the Duty Holder has defined the minimum purge rate for the flare and that they have arrangements in place for monitoring the purge rate.
- Confirm whether the installation has any atmospheric vents and ensure that a suitable assessment has been made with respect to gas dispersion. Ensure that any atmospheric vents are equipped with flame arrestors (or other suitable device for flash-back protection) and that they are subject to a maintenance programme.
- Confirm whether an HP/LP interface study has been completed.

**Matters of Evident Concern**

<b>Inspection finding</b>	<b>Examples</b>
Flare and relief system design is inadequate or unassessed	<ul style="list-style-type: none"> <li>• Relief and blowdown study has not been completed for the installation</li> <li>• Evidence of repeat failures during planned or unplanned blowdown events</li> <li>• Plant modifications completed which affect flare system and impact has not been reassessed, e.g. well tie-back</li> <li>• Failure to identify low temperature events during blowdown</li> </ul>

Inspection finding	Examples
Inadequate maintenance regime for relief devices	<ul style="list-style-type: none"> <li>• Absence of maintenance / inspection strategy for relief devices</li> <li>• Number of relief devices overdue for replacement</li> <li>• Duty holder cannot provide test certification for relief devices or demonstrate that installed devices are fit for purpose</li> <li>• No maintenance strategy in place for flame arrestors on vent systems</li> </ul>
Inadequacies in operation of flare system	<ul style="list-style-type: none"> <li>• Guidance not provided on minimum purge rates or start-up procedures for ensuring displacement of air from flare system following shutdown</li> <li>• Evidence of cold venting resulting in slumping of gas and touch-down on deck</li> <li>• Isolation valves on relief devices found in incorrect position whilst in service.</li> </ul>
Breach of HP/ LP interfaces	<ul style="list-style-type: none"> <li>• Inadequate control of HP/ LP interfaces, e.g. failure to provide suitable isolation arrangements</li> </ul>

## APPENDIX 5 - PROCESS ISOLATIONS

### Introduction

An effective means for the design, application, control and review of process isolations is critical for ensuring the prevention of hydrocarbon releases and thereby the potential for a Major Accident Hazard (MAH) to be realised. Failures in the isolation standard or control of isolations have contributed to some of the largest incidents experienced on the UK Continental Shelf (UKCS) as well as being a contributory factor to injury of personnel.

While predominantly focussed at the control of isolations on production installations, the basic principles can be applied to non-production installations.

### Scope

This guidance applies to inspection of isolation arrangements for both hydrocarbon and non-hydrocarbon systems and applies equally to production and non-production installations. The guidance is intended to relate to the isolation scheme itself and does not cover any associated activities such as a Duty Holders permit to work system.

The scope includes:

- Planning of isolations
- Application and proving of isolations
- Removal of isolations
- Locked Open and Locked Closed Valves
- Long term isolations
- Suitability of isolation devices

### Fundamental Requirements

The duty holder should have in place arrangements to manage the isolation of plant and equipment, to ensure that the uncontrolled release of flammable/toxic or other hazardous substances to atmosphere cannot occur.

Process isolations are typically associated with temporary changes to the state of the plant such as during planned maintenance work, start-up, shut-down or re-commissioning activities. They may also be used to protect against particular hazards, and be of a short or long term nature. Process isolations may also be used on mothballed equipment and should be given separate consideration.

Duty holders must ensure that the following elements are adequately addressed by their arrangements:

### Planning of Isolations

- An isolation standard, procedure or manual should be in place detailing all stages of the isolation from initial planning through application and ultimately removal. It should also outline how the competency and assessment of individuals shall be carried out.
- Hazards associated with isolated substances, and work tasks which may release them are identified as part of the isolation assessment process.
- The likelihood and potential consequences of failure of tasks reliant on isolations are assessed, throughout the lifecycle of the isolations (installation, work task, removal and reinstatement)
- Where long term isolations are intended to be used for supporting decommissioning or mothballing of redundant equipment then these should be assessed in terms of ensuring that the redundant equipment is sufficiently segregated from live process systems. Wherever possible, redundant equipment should be physically disconnected (air-gapped) or positive isolation (spade) put in place. The use of valve isolations as a long term isolation method on redundant equipment should generally be avoided.
- Isolation schemes are designed in accordance with an appropriate methodology, based on minimising the risk to ALARP (or positive isolation in the case of confined space entry). Isolation schemes should also consider the risk involved in applying the isolation (whether through time or hazard) compared to the duration and inherent hazard of the work task itself when considering what is ALARP.
- Higher risk isolations that do not meet the duty holder's 'baseline isolation standard' should be subject to additional risk assessment and a greater level of management approval including review by onshore personnel as necessary. This process should sufficiently identify the deviation from baseline standard, the associated hazard, and all reasonably practicable additional control measures to be put in place. Improvements to procedures/equipment to enable the baseline standard to be met in future should also be identified and assigned to appropriate responsible persons for consideration of future potential modifications.
- The use of own/ personal isolations should be limited and generally restricted to those work tasks of short duration and low risk.

### **Application and proving of Isolations**

- A controlled sequence of activities is used to minimise risk during installation of isolations.
- An appropriate standard of valves/ blanks/plugs/joints/spades/blinds and other fittings is used to effect isolations and secure closed any open pipework
- Installed isolation schemes are fully labelled, and cross-referenced to P&IDs or other suitable drawings, and work control documentation
- Checks to ensure that isolations and other plant preparation activity have been effective in removing the identified hazards are in place. Checks on effectiveness of isolations should include an appropriate method for testing the integrity of each isolation point. Where isolation integrity cannot be

achieved (or proven) then deviations should be risk assessed and justified accordingly.

- Planned isolation schemes are effectively documented and communicated to all who may be affected by them. Isolation schemes should be demonstrated to those undertaking the work task for which the isolation has been provided prior to the work task being started.
- All isolations shall be suitably secured to prevent the isolation point from being disturbed intentionally or otherwise. Securing of isolations can be achieved through such means as removal of valve handle, interlocks or chain and padlock.
- Routine, recorded checks of the status of isolations and associated controls are in place, at a suitable frequency

### **Removal of isolations**

- Isolations should only be removed once all work tasks associated with that isolation have been completed and all associated documentation closed out. Un-authorized/unintended removal of isolations should be prevented through a combination of training, competence and regular auditing.
- Where isolations points require to be disturbed during the work activity the Duty Holder should have a system in place for controlling the change in position of the isolation and ensuring that it is reinstated to its original position and where necessary retested.
- All isolation points, including bleeds, should be returned to their normal operating position once the formal isolation has been removed. The Duty Holder should have an effective system in place for the successful reinstatement of plant following work activities; refer to separate section of Inspection Guidance.

### **Locked open and locked closed valves**

- An assessment should be carried out to determine all critical valves on the installation and their required position. The assessment should consider such areas of concern as; management of HP/ LP interfaces, critical process control and shutdown transmitters, isolation valves on pressure relief devices, isolation valves on safety critical elements, e.g. firewater ring-main, hydraulic supplies to ESDV.
- Locking mechanisms should be appropriate for the valve being isolated. Where valve operation may be required as part of an emergency response then the locking mechanism should be both robust in preventing inadvertent movement but also allow for easy removal should it be required.
- Valves specified as locked open or locked closed as their normal operating mode should be clearly identified by name or number, on or near the valve, and on P&IDs or other suitable drawings.
- Valves should be positively secured so that significant movement is prevented. The reason for locking a valve should be known to personnel and specified in operating procedures.

- Locked valve status should be periodically checked, with the frequency taking into account the potential consequences of the valve being in the wrong position. More critical valves should be checked more frequently. Valves should be identified on a readily available register, with details of each valve, its location and status, and the checks carried out, including the date, the person doing the checking and the results.
- Changes in position of critical valves should be strictly controlled and effective measures in place to ensure that they are returned to their normal position on the completion of any associated work activity.
- Where duty/ standby relief devices are provided, the arrangement should ensure that one valve is on-line at all times. The preferred arrangement is through the use of a key interlock system however where this is not available then other suitable control measures should be in place to monitor the isolation. Where key interlock systems are used they should be designed such that valves are opened/ closed in the correct sequence to prevent inadvertent over-pressure.
- The use of interlock keys should be controlled, particularly if spare or master keys exist for maintenance purposes. Operating instructions for interlock systems should be available, with personnel trained in their use. Maintenance of the system is required, as keys and lock mechanisms can wear and keys can become misplaced.

### **Long term isolations**

- Where process equipment is isolated for extended periods of time (sometimes permanently) because it is not commissioned, redundant, only used infrequently or awaiting repair or modification, additional controls should be in place. These could include a register identifying all long-term isolations and the reasons for isolation, a procedure for checking the status and integrity of each isolation, and a system for periodic review of the status of each item, to decide if the isolation is still appropriate, if the plant should be removed, or if other action should be taken.

### **Suitability of isolation devices**

- Consideration should be given to the type of isolation device being used for the task and whether or not it is suitable. Such issues could include the valve type, method of integrity testing including the maximum test pressure capable of being applied and any valve characteristics that may impact on a suitable integrity test being carried out, e.g. floating ball, pressure activated seals.
- Where proprietary isolation methods are used, such as pipe freeze or mechanical plugs, the Duty Holder should have carried out an appropriate risk assessment of the isolation methodology to ensure it is ALARP. Special consideration should be given to those isolation methods where isolation integrity is dependent on the functionality of other systems and its fail safe position, e.g. de-energisation of pressure seals on mechanical plugs.

- Where positive isolations are put in place then any mechanical device, such as blank flange or spade, should be of suitable pressure rating and tested for the design pressure of the system being isolated.

### **Industry Standards and Guidance**

- API Standard 520, 'Sizing, Selection, and Installation of Pressure-relieving Devices : Part II – Installation', Sixth Edition, 2015

### **Relevant HSE Guidance**

- HSE Publication L65, 'Prevention of fire and explosion, and emergency response on offshore installations - Approved Code of Practice and Guidance', Third Edition, 2016
- HSE Publication HSG253, 'The safe isolation of plant and equipment', Second Edition, 2006

### **Inspection Approach**

- Request a copy of the Duty Holder isolation manual and confirm that it is in line with the expected guidance.
- Discuss the design and application of an isolation with those personnel deemed to be competent by the Duty Holder.
- Ask personnel involved in the isolation of the plant whether or not there are any issues with achieving the required level of isolations due to the suitability of the plant design or the condition of the equipment.
- Ask the Duty Holder to provide a copy of their defective valve register, or similar, and review to determine whether the number of defective valves could impact on the ability to safely isolate the plant or process.
- Ask the Duty Holder to provide a copy of the findings from any audits they have carried out on isolations and a demonstration that any findings have been acted upon.
- Select a sample of live isolations in place and ensure that they comply with the minimum required isolation standard as identified by the Duty Holder. Where an isolation does not comply with the minimum standard then assess the suitability of the supporting risk assessment.
- Review the sample of live isolations in-field and confirm that they are suitably tagged and secured in position with an appropriate locking mechanism.
- Select a sample of recently completed isolations and review in-field to ensure that they have been returned to their normal operating position, isolation tags removed and where the isolation point was a critical valve that it has been secured in its required position.
- Review the Duty Holder arrangements for reviewing their Locked Open/ Locked Closed valves and the frequency that checks are being carried out.

Inspect a sample of the valves in-field to confirm that they are in the correct position, suitably secured and identified with a locked open or locked close tag as appropriate.

- Review the Duty Holder arrangements for reviewing their Long Term Isolations and inspect a sample of long term isolations in field to confirm that they remain in the required position, are suitably tagged and secured.
- Confirm with the Duty Holder whether they have plans in place to reduce the overall number of long term isolations and how they ensure the integrity of the isolations. Particular consideration should be given to long term isolations on mothballed equipment which is reliant on valve isolation only and may give rise to other potential risks.

### Matters of Evident Concern

<b>Inspection finding</b>	<b>Examples</b>
Duty Holder does not have a suitable system in place for management of isolations	Isolation standard is not in compliance with recognised industry guidance Duty Holder does not have a system in place for ensuring the competency of personnel involved in the design and application of isolations
Isolations are not being effectively managed and controlled	<ul style="list-style-type: none"> <li>• No system in place for the review of locked open or locked closed valves</li> <li>• Duty Holder audits of isolation activities giving a high level of non-conformance</li> </ul>
Isolation arrangements are ineffective in practice	<ul style="list-style-type: none"> <li>• History of incidents relating to failure of isolation arrangements</li> <li>• Plant configuration does not allow easy isolation either due to initial design or high number of defective valves</li> </ul>

## **APPENDIX 6 - PLANT RE-INSTatement FOLLOWING MAINTENANCE OR AN IDLE PHASE**

### **Introduction**

Introduction of fluids into a process system that has recently undergone maintenance activity, or has been in an idle phase, has a number of associated hazards, and can be addressed as a particular form of management of change. Ineffective control of this process was clearly fundamental to the Piper Alpha disaster. In order to control the activity, effective application of PTW and isolation certificates is essential. There may however be other, wider considerations not traditionally captured under such safe systems of work.

### **Scope**

This guidance applies to inspection of any activities associated with returning equipment to service following a period of maintenance and is intended to cover simple scopes of work through to plant restart following a maintenance shutdown/turnaround.

The scope includes:

- Mechanical completion checks
- Pressure testing
- Start-up and monitoring

### **Fundamental Requirements**

The duty holder should have in place arrangements to manage the reinstatement of plant following a maintenance period, to ensure that the uncontrolled release of flammable/toxic or other hazardous substances to atmosphere cannot occur. Duty holders must ensure that the following elements are adequately addressed by their arrangements:

### **Mechanical Completion Checks**

- Where large scale maintenance work is being carried out, e.g. during a shutdown/ turnaround, consideration should be given to use of a flange break register, or similar, for tracking of disturbed joints/ flanges. The use of disturbed joint/ flange tags should also be used to aid identification.
- Visual checks should be carried out on all equipment following a period of maintenance to confirm that:
  - Maintenance activities have been completed as expected
  - Equipment is in place as per design
  - All isolations have been removed and critical valves returned to their normal positions
  - All vents/ drains are in their correct position and bleed points capped/ blanked

- All instrumented protective devices are lined up

## **Pressure Testing**

- The duty holder should have a procedure or policy in place that details the pressure testing requirements for equipment following a maintenance period and prior to return to service.
- Leak test procedures and marked-up drawings should be prepared in all cases except where the pressure test is limited to specific items of equipment and limited number of joints to be tested. The specific leak test procedure for that system should detail:
  - Which system is to be tested
  - Which test fluid to use. Pressure tests should be carried out using the lowest risk test fluid wherever possible.
  - What the test pressure is, hold duration or any performance standard to be achieved
  - Where the pressure test initially fails, a description of how it should be rectified and what re-testing is necessary
  - Relief routes to ensure that equipment is not inadvertently over-pressurised
  - Vent and drain paths to ensure leak test fluids are removed in a safe manner and consideration given as to whether any residue of test fluids will introduce any additional hazards (e.g. moisture in a dry/acidic system)
  - Required valve positions for the test
  - Inhibits and over-rides required for the test
  - Pass / fail / abort criteria
- Service testing of hydrocarbon systems, particularly gas systems, should generally be avoided unless there is no other alternative or if there is a greater risk by disturbing joints to achieve the required test.
- An assessment process should be in place where any requirements for service testing or deviation from normal pressure testing requirements are reviewed by the appropriate persons, including onshore personnel as necessary.
- Following an extended shutdown period, typically weeks to months, then consideration should be given to a pressure test of the complete system rather than only those sections which have been subject to any maintenance activity.

## **Start-up and Monitoring**

- Plant line-out checks should be carried out prior to restart and introduction of hydrocarbons to ensure that all valves are in their required position as identified by drawings and operating procedures. Plant line-out checks may be conducted in conjunction with mechanical completion checks but caution should be exercised as line-outs may be affected by pressure test requirements.
- Plant checks should also ensure that emergency systems that may be required to operate should a start-up be aborted are ready and that trip inhibits have been removed.

- Confirm that there are no actions, maintenance activities, modifications or other similar issues outstanding which could interfere with the start-up.
- Procedures should be in place for start-up of individual items of equipment or the entire plant. Where equipment is not available at start-up that affects the operation of the plant then a suitable risk assessment should be in place to ensure all controls and mitigating measures are in place.
- Start-up should be suitably planned to ensure that sufficient crew levels are in place and that the crew have sufficient knowledge, understanding and competency. Where possible, start-up timing should be selected to avoid critical activities being carried out at shift or crew change.
- Where start-up activities impact on other persons, installations, or pipelines, then arrangements should be in place to ensure that all parties are notified and that there are no reasons why start-up cannot take place.
- The duty holder should have arrangements in place for the monitoring of plant and equipment following start-up. Plant monitoring on start-up should be considered as a different activity than those normal operational checks and continue to be carried out at suitable intervals until the plant has reached normal steady-state conditions.

### **Industry Standards and Guidance**

- Energy Institute Publication, 'Guidelines for the management of the integrity of bolted joints for pressurised systems', Second Edition, 2007
- ASME Publication B31.3, 'Process Piping', 2016

### **Relevant HSE Guidance**

- HSE Publication L65, 'Prevention of fire and explosion, and emergency response on offshore installations - Approved Code of Practice and Guidance', Third Edition, 2016
- HSE Publication HSG253, 'The safe isolation of plant and equipment', Second Edition, 2006

### **Inspection Approach**

- Review any Duty Holder procedure associated with pressure testing of equipment and ensure that it is suitable, including the steps to be followed in the event of any deviation from normal testing requirements.
- Request a list of any recently completed maintenance activities as well as any associated documentation relating to the restart. Conduct a review of the information provided and confirm that all of the areas identified above were suitably addressed prior to bringing equipment back into service. Verify whether the aforementioned return to service checks are captured through checklists or similar. Particular consideration should be given to any equipment which is being recommissioned following an extended outage.
- Ask the Duty Holder to demonstrate their arrangements for management of disturbed flanges during maintenance periods.

- Where a maintenance activity is on-going at the time of inspection, discuss the task with the work party with a particular focus on the reinstatement activities to be carried out prior to bringing the equipment back into service.

### **Matters of Evident Concern**

<b>Inspection finding</b>	<b>Examples</b>
Duty Holder does not have a suitable system in place for the safe restart of plant	Duty Holder does not have a procedure for pressure testing of equipment Evidence of failures to confirm plant integrity prior to start-up, e.g. repeated instances of hydrocarbon release from vents/ bleeds Return to service checks are not formalised either through procedure or checklists Absence of suitable arrangements for witness joints including enhanced monitoring following start-up

## **APPENDIX 7 - MANAGEMENT OF CHANGE**

### **Introduction**

Many catastrophic events that have occurred on process facilities are attributable to poorly managed change. There have also been numerous deficiencies in offshore process systems arising from the failure to control change.

Typical examples of inadequate management of change include the failure to properly re-evaluate relief requirements for a separator when an additional tieback well is introduced, or equipment (such as a pump) is replaced with an alternative of different capability, or the assessment of flow capacity or mechanical integrity when the process fluids have changed, such as due to a movement from dry gas to wet gas operations, or increased water cut. Key safety issues include different corrosion/erosion rates, liquid slugging effects, increased pigging frequency, hydrate formation/inhibition, and effects on blowdown, flare and vent systems.

### **Scope**

This appendix provides guidance on inspection of duty holders' management of change, including how it is initiated, communicated, analysed, implemented, and reviewed.

### **Inspection Guidance**

#### **Fundamental Requirements**

Duty holders need to have systems to ensure that deliberate changes to the process and its equipment, or to the management system, are properly evaluated before their introduction. In particular, any hazards with potential impact on safe process operations associated with the change should be identified, the risks of these assessed, and appropriate measures selected to control them.

A formal written procedure should describe how change is to be managed. All changes will require formal change control; the extent and nature of this may vary depending on the type of change. The procedure should identify:

- Scope of application
- Roles and responsibilities
- Risk analysis (hazard identification and risk assessment)
- Communication (including notification) requirements
- Training requirements
- Implementation process for changes
- Arrangements for monitoring and review.
- MOC authorisation
- Handover arrangements

- Pre-start up safety review
- Update of documentation and records, e.g. Operating Procedures, P&IDs
- Close-out

The procedure should also draw reference to:

- Evidence from previous incidents – their causes and means of preventing them
- Hazard evaluation requirements
- The options that are available in the design of safety measures

### **Scope of application**

Types of change which should be considered include:-

- Major plant additions or modifications
- Changes in process operating parameter (control, alarm, or trip setting)
- Changes in mode of operation
- Replacement of equipment with non-identical parts or addition of new equipment (whether for safety-related purposes or not)
- A change out with the design intention
- Organisational changes
- Temporary changes
- Changes with impact on the operational safety case.

Changes may affect other parts of the plant which may be quite remote from the source of the change. Therefore all parts of the plant should be considered in undertaking hazard identification and risk assessment.

In addition, change can happen over time in a gradual way, and without a particular initiating event that can easily be recognised. It is important therefore that retrospective/periodic reviews of process related hazards also occur, and attempt to identify changes which may otherwise have been missed.

Duty Holders should also exercise caution when doing 'like for like' replacements as equipment may have been amended by the supplied over time. These subtle changes may not be obvious and may result in an item of equipment be unsuitable for use. Any 'like for like' change should be fully assessed by relevant Duty Holder personnel to ensure that the equipment is identical and does not need to be subject to a management of change.

### **Roles and responsibilities**

Post-holders who can authorize different types of change should be clearly identified. Technical Authorities should be involved within the review and approval process to ensure that any change does not introduce any additional risk or impact on the safe operation of the plant. The Duty Holder should also have arrangements in place for engagement with the ICP through the

management of change process to ensure that any impact on a SECE is fully assessed.

Whilst the authorisation of change should be tightly controlled by a small number of individuals, the opportunity for proposing changes should be widely available to people associated with the process systems. Good practice includes provision for feedback on the reasons why each proposal has or has not been approved. Before changes are made, the workforce should be consulted.

### **Hazard identification and risk assessment**

Process and plant modifications should not be undertaken without having undertaken a documented safety, engineering and technical review (including review by the ICP for assessment of impact on any SECE). The review should consider any aspect of the change which could introduce a new hazard or adversely affect an existing hazard. This could include changes related to the following factors (although others may also be applicable):

- Process conditions
- Operating methods and procedural controls
- Engineering methods
- Safety
- Environmental conditions
- Engineering hardware and design
- Organisational arrangements

Once the specific changes are identified, a variety of hazard identification tools are available to assess them, including HAZID, HAZOP, FMEA, Fault tree, Cause-Effect, What-If etc. Each has its own strengths and weaknesses, and suitability for assessing particular types of change, and procedures should specify a type appropriate to the nature of the change.

Any risk assessment (or safety study) carried out must also be suitable and sufficient. Where hazards are identified, the risks may be assessed qualitatively or quantitatively. For most change control applications risk will be evaluated qualitatively using a form of risk matrix. Where risks are computed numerically then there must be a measure by which suitable comparisons of benefit vs. risk may be made. This may take the form of an implied cost of avoiding a fatality. If the risks are found to be intolerable and cannot be reduced, then the change must not be implemented.

### **Communication and notification requirements**

All those impacted by a deliberate change should be made aware of it, before it occurs. This should provide the opportunity to understand the change, the reasons for it, and to be aware of any changes in ways of working relevant to individuals that are necessary to ensure the change can be implemented successfully.

## **Training**

The hazard assessment should identify the need for, and nature of, any training required by staff in order to implement and operate the change successfully. This may range from a simple written communication, to an 'offline' training period away from the normal workplace, depending on the scale of the change. Some elements of training may need to be delivered to all affected staff before the change is implemented, whereas some may only be possible or appropriate once the change is in place. An example may be where some theoretical/classroom type training can be provided in advance before a new process plant system is constructed, but follow-up training on the installation is required during commissioning/start-up to provide practical experience.

## **Implementation process**

Electronic and/or paper-based records of each management of change and its implementation should be maintained throughout its lifecycle. The assessment of the change should be included within the documentation and include:

- A detailed description of the change, with associated drawings/schematics
- A record of the hazard identification
- Assessment of the likelihood and consequence of the resultant risks
- A record of the measures selected to control the risks
- A record of the authorisation of the change to proceed, and identification of who is responsible for leading the various phases of the implementation of the change
- Identification of any hold points in the implementation of the change, beyond which further authorisation to proceed is required.

Control measures arising from the assessment, such as actions from HAZOP studies, training requirements, leak testing processes, documentation updates etc. should be tracked for completion. Some of these actions may be required to be completed before implementation of various phases of the change (e.g. introduction of well-fluids) whereas some may be completed at the end of the change. The risk assessment should identify any such requirements.

## **Monitoring and review**

There should be clear mechanisms for monitoring application of the procedure to ensure that it is not short-circuited or missed out altogether.

Risk assessments can sometimes become mechanistic and superficial. Duty Holders should ensure that the quality of risk assessment, and the implementation of prescribed control measures, is monitored.

Safety risks have arisen when longer term actions identified by the management of change process have not been implemented. These have included examples such as:

- Operating procedures updates
- P&ID or equipment maintenance schedule updates
- Revisions to pipework support arrangements post commissioning
- Training completion
- Plant labelling
- Removal of redundant equipment

Completion of actions and closure of management of change assessments should be tracked.

### **Temporary Changes**

Temporary changes require to be assessed in a similar way to permanent changes. There needs to be a defined duration for which a temporary change can be applied. Maintenance and inspection of temporary equipment needs to be defined and included in the installation maintenance system.

### **Organisational changes**

Organisational changes such as reducing staffing levels, using contractors or outsourcing, combining departments, or changes to roles & responsibilities are usually not analysed and controlled as thoroughly as plant or process changes. Such changes can, if inadequately conceived or implemented, have a detrimental effect on safety. Even subtle changes to organisations can have significant impacts on the management of hazards.

The direct and indirect effects of a proposed organisational change on the control of hazards should be planned, identified and assessed in a similar way to plant/hardware changes. In particular, two aspects need assessment:

- Risks and opportunities resulting from the change itself
- Risks arising from the process of change

Staff (including contractors) should be consulted before, during and after the change.

All key tasks and responsibilities performed by the organisation subject to change should be identified. A mapping exercise should then be performed to describe how (and by whom) these will be performed in the new organisation. Any gaps in this mapping, and the capability of the new organisational arrangements to perform its functions should be identified, assessed, and measures selected to control the risks appropriately.

Matching of personnel and their skills to the requirements of any new tasks is necessary for selection, and to identify outstanding training requirements. Training and experienced support/supervision for staff with new or changed roles should be provided, following any identified needs.

Consideration should be given to review of plans and assessments by independent internal or external experts.

### **Periodic reviews**

The requirement for safety case thorough reviews; should drive duty holders to periodically examine their safety case, and in particular ensure that all hazards with the potential to cause a major hazard have been identified, all major accident risks have been evaluated, and that suitable measures have been taken to control those risks.

Good practice in the area of process plant hazard reviews includes the use of P&ID or system level hazard and operability studies (rather than line by line nodal reviews), and “bow-tie” re-assessments, involving both operational staff, and independent facilitators or technical experts. Other topics which should be considered as part of reviews include procedural changes, learning from previous incidents, or changes in industry or HSE codes, standards and guidance.

### **Industry Standards and Guidance**

- BS EN 61882:2016 Hazard and operability studies (HAZOP studies). Application guide
- Energy Institute, Guidance on meeting expectations of EI Process safety management framework, Element 12: Management of change and project management
- Kletz T.A., ‘HAZOP and HAZAN: Identifying and Assessing Process Industry Hazards’, Third Edition, IChemE, 1992.

### **Relevant HSE guidance**

- HSE Publication, ‘Human Factors Toolkit, Organisational change and transition management’ available at <http://www.hse.gov.uk/humanfactors/topics/specific3.pdf>

### **Inspection Approach**

- Request a copy of the management of change procedure; confirm the types of change included to ensure all types of change are included.
- Request a copy of the change register to review the types of changes being carried out, the progress and status of changes. Each change should include a summary table detailing the assessments to be completed, documents to be updated and any Safety Case revision requirements.
- Select several changes of different types and review the associated documentation and risk assessments carried out. Review the training and close out requirements.
- For a completed change, review the documentation which has been updated to confirm it has been suitably completed. Review training records if applicable.

- Review changes with offshore personnel. Ensure that operations and maintenance personnel are aware of changes and the implications of them.
- Review a temporary change to ensure it is correctly assessed and any maintenance and inspection is included in the maintenance management system.
- Ask the Duty Holder whether any 'like for like' change has been completed recently and what review they carried out to ensure that it was indeed a 'like for like' change.

### Matters of Evident Concern

Inspection finding	Examples
No formal / weak change control procedure in place.	<ul style="list-style-type: none"> <li>• Change control procedure does not define risk assessment requirements for different types of change.</li> <li>• No formal change control procedure for set points</li> </ul>
Assessment records not available	<ul style="list-style-type: none"> <li>• No records of HAZID, HAZOP etc. provided with change</li> <li>• Outputs from assessments not being managed to close out</li> </ul>
Procedures and drawings not updated within required time scale	<ul style="list-style-type: none"> <li>• Operating procedures and P&amp;IDs not updated</li> </ul>
Lack of training	<ul style="list-style-type: none"> <li>• Training matrices do not include training updates for new/ modified plant and equipment.</li> </ul>
Temporary changes being "updated" and remain live far beyond allowable duration.	<ul style="list-style-type: none"> <li>• Equipment installed for longer than allowed by Duty Holder procedures, e.g. 6 months, and no longer term change initiated</li> </ul>

## APPENDIX 8 - OTHER OFFSHORE PROCESS HAZARDS

### A) CONTROL OF H<sub>2</sub>S AND CO<sub>2</sub>

#### Introduction

Hydrogen sulphide (H<sub>2</sub>S) and carbon dioxide (CO<sub>2</sub>) may be present in well fluids, and consequently in hydrocarbon process systems. Both have a number of properties which make them hazardous, and effective measures need to be in place to manage the associated risks.

#### Hazards of H<sub>2</sub>S and CO<sub>2</sub>

H<sub>2</sub>S is a very toxic, flammable gas. It is pungent (rotten egg odour) at low concentrations, and irritates the eyes, nose and throat. At higher concentrations it rapidly destroys the sense of smell, and can cause unconsciousness and death. It is heavier than air and may accumulate in low-lying areas. H<sub>2</sub>S is toxic at breathable concentrations between 500-1000ppm, but death is not instantaneous. However, at concentrations of greater than 1000ppm, H<sub>2</sub>S is rapidly lethal

H<sub>2</sub>S in hydrocarbon fluids has the potential to form sulphur dioxide (SO<sub>2</sub>) via combustion, therefore flaring hydrocarbon gas containing measurable quantities of H<sub>2</sub>S needs to be carefully managed to ensure that the SO<sub>2</sub> produced does not present a toxic hazard.

H<sub>2</sub>S can also start to become an issue when reservoirs begin to mature. In addition H<sub>2</sub>S may arise in drilling muds, sewage, seawater systems, etc.

At room temperature and atmospheric pressure CO<sub>2</sub> is a colourless and odourless gas. CO<sub>2</sub> is not flammable and will not support combustion; hence it is sometimes deployed in fire suppression systems.

CO<sub>2</sub> can act as an asphyxiant, through displacement of oxygen to dangerously low levels. For CO<sub>2</sub> to reduce the oxygen concentration in air down to a level that is immediately dangerous to life, the CO<sub>2</sub> concentration would need to be in the order of 50% v/v. CO<sub>2</sub> also has a toxicological impact on the body when inhaled at lower concentrations of up to 15% v/v.

As the concentration of CO<sub>2</sub> in air rises, it can cause headaches, dizziness, confusion and loss of consciousness. The latter poses a risk of injury from falling. Since CO<sub>2</sub> is heavier than air, fatalities from asphyxiation have occurred when, at high concentrations, it has entered confined spaces such as tanks, sumps or cellars and displaced oxygen. It is also possible for CO<sub>2</sub> to accumulate in trenches or depressions outside following leaks and this is more likely to occur following a pressurised release where the released CO<sub>2</sub> is colder than the surrounding air

Risks arising from the presence of H<sub>2</sub>S/ CO<sub>2</sub> should be assessed, and appropriate controls put in place, based on recognised codes and standards.

Controls should include actions to keep process plant within safe operating limits, through start up, normal operation and shutdown phases, and also in particular cover any maintenance activity which may involve 'break-in' to process plant containing H<sub>2</sub>S/ CO<sub>2</sub>. Consideration should also be given to any treatment options, where available, for the reduction in concentration of H<sub>2</sub>S/ CO<sub>2</sub>

Areas of the installation where the risk of exposure to H<sub>2</sub>S/CO<sub>2</sub> is greater may typically be subject to additional access controls, or RPE requirements to reduce the risk of individual exposure. These should be clearly denoted/ signed, and appropriate training provided as to the requirements.

Where, through loss of containment, accumulations of H<sub>2</sub>S/CO<sub>2</sub> may occur, gas detection and alarm systems should be provided however it should be recognised that fixed detection may not always pick up a release and alternative forms of detection should be considered, e.g. portable detectors, when responding to a potential release. Emergency response plans should also reflect the potential for the presence of H<sub>2</sub>S/CO<sub>2</sub>.

H<sub>2</sub>S/CO<sub>2</sub> form corrosive acidic solutions in the presence of water and can adversely affect equipment and pipework through corrosion and sulphide stress cracking. In view of the hazardous and toxic nature of these gases, maintaining the integrity of the plant is essential. An effective system should be in place to monitor the condition of pipework and equipment. Repairs and replacement of plant must be to a suitable standard (e.g. the NACE standard for equipment containing H<sub>2</sub>S)

It is particularly important to make adequate preparations and have adequate safeguards for the presence of H<sub>2</sub>S/CO<sub>2</sub> in the well fluids during well testing when the actual composition of the well fluids is not known and the level H<sub>2</sub>S/CO<sub>2</sub> has not yet been determined.

### **Industry Standards and Guidance**

- API RP 55 - Conducting Oil and Gas Producing and Gas Processing Plant Operations Involving Hydrogen Sulphide.
- ISO 15156 Materials for use in H<sub>2</sub>S-containing environments in oil and gas production.

### **Relevant HSE guidance**

- HSE Publication, 'HSE Offshore COSHH Essentials, OCE6: Hydrogen Sulphide', available at <http://www.hse.gov.uk/pubns/guidance/oce6.pdf>
- HSE Publication, 'HSE Offshore Information Sheet No. 6/2009 - Managing hydrogen sulphide detection offshore', available at <http://www.hse.gov.uk/offshore/infosheets/is6-2009.htm>
- HSE Publication, 'HSE Offshore Information Sheet No. 4/2008 - The risks posed by exposure to inerting gases in the open air', available at <http://www.hse.gov.uk/offshore/infosheets/is4-2008.pdf>

- HSE Publication L5, 'Control of substances hazardous to health – Approved Code of Practice and guidance', Sixth Edition, 2013

### Inspection Approach

- Request information on well fluids characterisation from the Process TA or offshore operations team. This should contain information on the level of H<sub>2</sub>S/CO<sub>2</sub>.
- Review operating procedures to determine the level of information provided about the presence and dangers of H<sub>2</sub>S/CO<sub>2</sub>. The procedures should include information on how to prevent exposure, and how to respond in the case of a release.
- Determine whether there are any access control systems in place for parts of the installation where the exposure risk is greater. Are the systems effective?
- Identify whether toxic gas detection is provided for parts of the installation where H<sub>2</sub>S/CO<sub>2</sub> may accumulate in the event of a release (recognising the potential low levels and inability of fixed detection to identify). Are the locations of the detectors appropriate, and are the systems functional?
- Observe any equipment or PPE provided to mitigate against the effects of a release. Check their locations and how accessible they are. Have the operations personnel been trained on how to use them?
- Request for procedures regarding emergency flaring of sour gas. The duty holder should have assessed the risk posed by emergency flaring of sour gas and considered the effects of wind speed and direction and dispersion.

### Matters of Evident Concern

Inspection finding	Examples
Presence of H <sub>2</sub> S not verified	<ul style="list-style-type: none"> <li>• Duty holder has not carried out sufficient sampling and testing of the well fluids to ascertain the presence and/or levels of H<sub>2</sub>S present.</li> </ul>
No arrangements for dealing with the effects of a release H <sub>2</sub> S/CO <sub>2</sub>	<ul style="list-style-type: none"> <li>• Where the presence of H<sub>2</sub>S/CO<sub>2</sub> is anticipated but there are no plans or arrangements in place for dealing with the effects of a release.</li> </ul>
Inadequate material selection for process plant	<ul style="list-style-type: none"> <li>• The material selection study has not taken account of the presence of H<sub>2</sub>S/CO<sub>2</sub>.</li> </ul>
Inadequate sampling arrangements for process streams containing H <sub>2</sub> S/CO <sub>2</sub>	<ul style="list-style-type: none"> <li>• Where the presence H<sub>2</sub>S/CO<sub>2</sub> is anticipated but the sampling arrangements have not taken this into consideration and included the necessary precautions.</li> </ul>

## **B) SAND MANAGEMENT**

Production of sand with well fluids presents several potential hazards for topsides pipework and equipment, for example:

- Sand plugging causes valves to seize, potentially compromising ESD action.
- Accumulated sand requires operator intervention to remove it, by sand-washing, digging out, or dismantling of plate exchangers.
- Sand accumulation can prevent corrosion inhibitor reaching the material surface leading to increased corrosion.
- Sand accumulation in level instruments and bridles can lead to false readings and poor control, and may compromise shutdown initiation.

Risks arising from presence of sand should have been assessed, and appropriate controls put in place. Sand management strategies may aim to prevent sand production, or may rely on monitoring to avoid loss of containment. The following elements should be included in any strategy:

- A policy or strategy statement as to how sand hazards are managed
- Arrangements for assessment of sand-related hazards
- A reservoir management strategy for sand control
- Sharing of experience of sand problems with others.

Effective systems should be in place, onshore and offshore, for the management of sand production:

- If the sand management strategy allows some sand production, limits on sand production should be set
- Lesson learned from flowline inspection programmes should be captured
- Operating conditions, particularly fluid velocity, should be optimised to minimise erosion
- Wall thickness checks, of critical areas of pipework, should be undertaken
- The verification body should verify the effectiveness of the sand management strategy.

If sand monitoring systems are provided:

- The philosophy for sand monitoring should be clear, i.e. is it alarms only, periodic measurement, or continuous monitoring?
- Sand monitoring instruments should be calibrated.
- 'Trending' the results should facilitate deterioration over time to be measured
- If results from one instrument are used to infer conditions in other places, (e.g. monitoring on one flowline used to infer conditions in other flowlines), the validity of the assumptions used should be robust
- Appropriate actions should be taken if alarm limits are exceeded.

Operators should be aware of the hazards associated with sand production and the limits of individual wells and operating plant. Operating procedures may include:

- Restrictions on the operation of individual wells or systems
- Control of the operation of chokes to avoid settings where erosion may occur
- Procedures for removal of sand from vessels, etc.

### Industry Standards and Guidance

- DNVGL-RP-O501 'Recommended Practice – Managing Sand Production and Erosion', August 2015

### Relevant HSE Guidance

- HSE Publication L65, 'Prevention of fire and explosion, and emergency response on offshore installations - Approved Code of Practice and Guidance', Third Edition, 2016

### Inspection Approach

- Identify whether there is history of sand production from the wells and what the Duty Holder approach is for sand management, e.g. sand detection, separator sand-wash facilities etc.
- Determine whether or not there have been any loss of containment events associated with sand production. If historical, or repeated, failures due to presence of sand then investigate what remedial action the Duty Holder has taken to address the issue.
- Determine whether the presence of sand is causing any operational problems, e.g. impact on separator level transmitters, damage to equipment etc, and any remedial actions taken by Duty Holder to address the issue.

### Matters of Evident Concern

Inspection finding	Examples
Change in sand production from wells and the increased risk has not been assessed	<ul style="list-style-type: none"> <li>• Increased loss of containment events due to sand erosion</li> <li>• Sand production is resulting in operational problems and damage to equipment</li> <li>• Process plant is not designed for sand loading and no facilities in place for management</li> </ul>

Inspection finding	Examples
Absence of sand management strategy	<ul style="list-style-type: none"> <li>• Sand production is not being managed through effective operational / procedural control</li> <li>• No procedures or guidance in place for response to increased sand production</li> </ul>

## C) CONTROL OF HYDRATES

### Introduction

Hydrates are crystalline solids wherein guest (generally gas) molecules are trapped in cages formed from hydrogen bonded water molecules (host). They look like ice, but unlike ice can form at much higher temperatures. The presence of the gas molecules give extra attraction, hence stability, fixing the position of the water molecules.

Hydrates are formed by gas cooling to below its water dew point, or when free water is present. Cooling may be due to an operational pressure drop, when pipelines or systems are shut down and allowed to cool at operating pressures or during start-up when hydrocarbon is introduced into cold pipework or equipment.

Hazards caused by hydrates include:

- Blockages in pipelines and wells.
- Blockage of pipework, and instrument tappings, causing false readings.
- Plugging of valves, giving operational problems, and potentially compromising ESD action.
- Hydrate particles travelling at high gas velocities can cause erosion at elbows and tees.

A good understanding of the hydrate formation regions in the wells, pipelines and plant is required by technical and operations staff. The temperature and pressure conditions at which hydrates form can be modelled and are a function of the composition of the fluids present in the system.

Once hydrates have formed, removing them requires careful consideration; it is therefore preferable to prevent their formation. Hydrate problems can be avoided by water removal (dehydration), increasing the system temperature, reducing the system pressure, or by injection of inhibitors. There are thermodynamic inhibitors (methanol, ethanol and glycols) and low dosage kinetic hydrate inhibitors and anti-agglomerants.

Removal of hydrates may require physical intervention, with associated risks. If hydrate plugs form there may be large slug forces at bends and tees in piping systems. There are also hazards associated with methanol injection into wells and flowlines, where pressures may be >100 bar.

## **Scope**

This guidance applies to inspection of the measures put in place by the duty holder to address the presence or potential of hydrates in the process systems associated with the installation.

## **Fundamental Requirements**

The potential for hydrate formation under non-routine activities should be addressed in operating procedures. These should include:

- Actions to keep within safe limits by preventing hydrate formation, and the consequences of failing to do so
- Procedures for start-up, normal operation and shutdown
- Contingency procedures e.g. for situations where hydrate formation is suspected, or where the supply of inhibitor is interrupted.

It is essential that the hydrate inhibitor is present at the point where gas / condensate is cooled to its hydrate formation temperature. Therefore injection should be upstream of control valves, choke valves or any place where pressure reduction takes place. The flowrate of inhibitor required should be determined based upon the hydrocarbon flowrate.

## **Industry Standards and Guidance**

- Canadian Association of Petroleum Producers Publication "GUIDE - Prevention and Safe Handling of Hydrates" 2013 Review

## **Relevant HSE Guidance**

- HSE Publication L65, 'Prevention of fire and explosion, and emergency response on offshore installations - Approved Code of Practice and Guidance', Third Edition, 2016
- HSE Publication HSG253, 'The safe isolation of plant and equipment', Second Edition, 2006

## **Inspection Approach**

- Request information on hydrate formation from the Process TA and Operations Team Leader.
- Review operating procedures to determine the level of information provided about the occurrence of hydrates within the wells, pipelines and process systems. The procedures should include both hydrate inhibition and hydrate dispersal if a hydrate forms.
- Ask operations personnel about hydrate management and whether hydrates occur within the plant. Ensure operations personnel know the correct actions to take in the event of hydrate formation.

## Matters of Evident Concern

Inspection finding	Examples
Location of likely presence of hydrates in system not identified.	<ul style="list-style-type: none"> <li>Information on the propensity to develop hydrates within the wells, pipelines, pipework and vessels not included in base documentation</li> </ul>
No hydrate inhibition arrangements	<ul style="list-style-type: none"> <li>No clear inhibition philosophy and procedures provided.</li> <li>No permanent inhibitor injection facilities installed.</li> <li>Inhibitor dosage rates not defined.</li> <li>Injection quills not maintained.</li> </ul>
No hydrate dispersal arrangements	<ul style="list-style-type: none"> <li>No permanent methanol injection facilities provided.</li> <li>Injection points incorrectly located.</li> </ul>
Gas dehydration failing to adequately dry gas	<ul style="list-style-type: none"> <li>Failure to maintain gas dehydration performance resulting in wet gas being present in the high pressure sections of the plant with risk of hydrates when temperatures are reduced (compressor discharge cooler, gas lift chokes, pressure control valves).</li> </ul>

## D) SAMPLING ARRANGEMENTS

### Fundamental Requirements

Fluid sampling involves breaking into the hydrocarbon containment envelope and managing high pressure (up to ~700bar), toxic and flammable gasses. Hazards associated with potential loss of containment, and static electricity, should be recognised. The hazards associated with breaking into the hydrocarbon containment envelope should be specifically addressed in procedures for interventions into the process plant.

A risk assessment of the sampling work associated with temporary equipment should take account of connected (host) plant. Only properly designed and designated sample points should be used for taking samples.

There is a hierarchy of sample system design; where a sample needs to be taken, an enclosed method should first be considered; some samples may be taken online in a closed loop, and a 'sample bomb' may otherwise be used to avoid breaking containment. Specifications should be available for pressure ratings of sample bombs and there should be a system in place to assure the integrity of the pressure containing sampling equipment.

Taking an open sample directly from a live system is potentially the most hazardous method. For the simplest two valve sample arrangement, a ball valve and needle valve combination, with the ball valve closest to the live process, is the best practice. A needle valve closest to the process might be subject to wash through, while a system with a ball valve in the outer position leaves too great a flow area; the needle valve offers greater control at the point of sampling.

A major hazard involved with the transfer of flammable liquids is the build-up of static due to charge separation with potential for static discharge resulting in fire / explosion. For open sample connections the design of the system should prevent the accumulation of any static electrical charge, for example, by the avoidance of non-conducting surfaces and the bonding of metal parts. Efficient static bonding connectors should be provided.

It is recommended that for fluid transfer, non-conducting hand held containers of more than 20 litres capacity (the size of standard petrol can), should not be used without special precautions; we should interpret this as requiring special treatment in the risk assessment. When a liquid of low conductivity is being handled, and various other specified precautions are applied, a small electrostatic charge may remain, but it is common practice to use high resistivity containers with capacities up to 5 litres.

### **Industry Standards and Guidance**

- BSI Publication PD CLC/TR 60079-32-1, 'Explosive Atmospheres Part 32-1: Electrostatic Hazards, Guidance'
- National Fire Protection Association (NFPA) Publication\_NFPA 77, 'Recommended Practice on Static Electricity'

### **Relevant HSE guidance**

- HSE Research Report RR804, 'Plastic Containers for Flammable Liquids/ Hazardous Areas – Electrostatic Risks', available at <http://www.hse.gov.uk/research/rrpdf/rr804.pdf>

### **Inspection approach**

- Identify all sampling taking place on the installation and request a copy of the procedures covering these sampling activities. Ensure that the procedures adequately describe the method for taking a sample including any special precautions, e.g. container type, static discharge etc.
- Review whether inhibition of any protective device, e.g. fire & gas detection, is required during sampling. Where inhibition is required, ensure that this is indeed necessary and that it is also being properly controlled.
- Inspect the sampling arrangements in-field and confirm that they are appropriate for the type of sample being taken, are in good condition and include sufficient isolation arrangements.

- Identify all personnel responsible for taking samples and ensure that they have been provided with adequate training and information. In general, production technicians should be permitted to carry out low-risk sampling activities, e.g. OIW, BS&W, with high-risk sampling, e.g. H<sub>2</sub>S, gas bombs, carried out by the production chemist (or equivalent).

### Matters of Evident Concern

Inspection finding	Examples
Failure to control ignition sources	<ul style="list-style-type: none"> <li>• Uncontrolled and unassessed plastic containers used to take hydrocarbon samples from plant.</li> <li>• Mobile equipment not earth bonded (including pumps and drain hoses).</li> </ul>
Operational Procedures are insufficient	<ul style="list-style-type: none"> <li>• Procedures do not cover all the potential sample arrangements on the installation.</li> <li>• Sampling procedure allows blanket inhibition of local sample area, without sufficient oversight/assessment.</li> </ul>
A lack of competency of the sampling personnel	<ul style="list-style-type: none"> <li>• Trainees are allowed to take samples unsupervised</li> <li>• There are no competency requirements in the CMS for sample taking.</li> </ul>
Equipment for sampling is not fit for purpose	<ul style="list-style-type: none"> <li>• Where samples are taken to atmosphere, a double ball valve arrangement is used, rather than a combination involving a needle valve.</li> </ul>
Generic Permits for sampling	<ul style="list-style-type: none"> <li>• Permits are generic allowing the sampler broad access to any part of the plant during the day; potential to interfere with other work scopes.</li> </ul>

### E) PROTECTION AGAINST AIR INGRESS AND FLAMMABLE MIXTURES IN PROCESS PLANT

Flammable mixtures can form in piping, plant and equipment when air enters systems that normally contain hydrocarbon, as a result of operational or maintenance activities.

Inert gas purging with nitrogen is often used to remove hydrocarbons from process equipment, without taking it through a flammable mixture regime. Correct purging and operational procedures will ensure that the risks are minimised.

It is important however to ensure that the reverse flow of hazardous fluids into the inert gas purging system cannot occur, as there is a risk of a flammable or toxic atmosphere being inadvertently generated elsewhere. Controls typically include:

- Ensuring that the supply gas always has a higher pressure than the system being purged
- Interlocks between purge gas supply isolations and system inlet isolations
- Use of non-return valves in the purge gas supply
- Local procedures/links with isolation certificates

Inert atmospheres generated by purging processes need to be safely vented, and in particular prior to disconnection of any temporary purging connections, due to the risk of local low concentrations of oxygen being generated.

Purging of flare and vent headers is required to prevent air ingress, which could lead to formation of a flammable mixture. Required purge rates may vary depending on the operating mode. If there are sufficient continuous and incidental discharges from the process into the flare system a minimum purge rate may be acceptable. Purge points should be located at the upstream end of headers to ensure that there are no dead legs. Alternative supplies of purge gas (e.g. nitrogen, fuel gas or propane) should be available, and used when the normal supply is not available. Procedures should be in place for purging of flare headers following shutdowns (or periods where flare is extinguished) to ensure that any air is displaced and the risk of a flammable atmosphere eliminated prior to flare ignition. Process gas may be used for purging of the flare prior to start-up provided it is of sufficient rate and volume to give an effective purge.

Fuel gas or nitrogen may also be provided to some tanks and vessels (such as methanol or glycol storage tanks, cooling/heating medium expansion vessels or open/closed drains tanks) to maintain system pressurisation, allow for expansion/contraction or to exclude air to prevent formation of an explosive atmosphere or to prevent chemical degradation.

Procedures for maintenance intervention, and for restoring equipment back into service, should address the control of any flammable atmosphere that may be formed. Purging with nitrogen or other inert gas, prior to intervention or restoring equipment back into service, will minimise the flammable atmosphere. Following maintenance, sampling of the 'inert' atmosphere should be undertaken to ensure that the oxygen content is less than a specified amount (typically <5% O<sub>2</sub>). Duty Holder procedures should give guidance on plant purging requirements for maintenance activities.

For interventions that are carried out routinely, e.g. pig traps, dedicated arrangements for purging and venting should be provided. If tanks or caissons are opened for maintenance from which hydrocarbon cannot be fully removed special precautions may be necessary (e.g. continuous purging or foam blanketing).

If nitrogen is produced on the installation using a nitrogen generation plant, the quality of the nitrogen should be assured, and high levels of oxygen in the 'inert' product gas prevented.

## **Industry Standards and Guidance**

- API Standard 521, 'Pressure-relieving and Depressuring Systems', Sixth Edition, 2014
- BS EN ISO 23251, 'Petroleum, petrochemical and natural gas industries – Pressure-relieving and depressuring systems', 2008
- Energy Institute Publication, 'Guidelines for the safe and optimum design of hydrocarbon pressure relief and blowdown systems', 2001

### Relevant HSE Guidance

- HSE Publication L65, 'Prevention of fire and explosion, and emergency response on offshore installations - Approved Code of Practice and Guidance', Third Edition, 2016
- HSE Publication HSG253, 'The safe isolation of plant and equipment', Second Edition, 2006

### Inspection Approach

- Review the operating procedure for the flare system and confirm that it provides sufficient guidance in relation to safe operation of the flare. In particular, consider the guidance provided on minimum flare purge, precautions for start-up and any weather related provisions (gas dispersion impacts).
- Verify that the Duty Holder has defined the minimum purge rate for the flare and that they have arrangements in place for monitoring the purge rate.
- Review Duty Holder guidance / procedures for plant preparation for maintenance and subsequent return to service. Ensure that sufficient guidance is provided for purging of plant during maintenance activities.
- Where pigging facilities are provided, ensure that they have suitable arrangements in place for purging of launchers/ receivers prior to opening the launcher and also before introducing hydrocarbons. Verify that pigging procedures also give sufficient guidance on the purging requirements.

### Matters of Evident Concern

Inspection finding	Examples
Inadequacies in operation of flare system	<ul style="list-style-type: none"> <li>• Guidance not provided on minimum purge rates or start-up procedures for ensuring displacement of air from flare system following shutdown</li> </ul>
Inadequate purging arrangements for pig launchers / receivers	<ul style="list-style-type: none"> <li>• No purge connections are available on pig launchers / receivers</li> <li>• Pigging procedures do not contain guidance on purge requirements prior to breaking of containment or reintroduction of hydrocarbons.</li> </ul>

Inspection finding	Examples
Plant preparation for maintenance insufficient	<ul style="list-style-type: none"> <li>No guidance to operations personnel on plant purging requirements prior to carrying out or following completion of maintenance</li> </ul>

## F) DRAIN SYSTEMS

### Fundamental Requirements

There are typically three drains systems on an offshore installation; Open Hazardous drains, Open Non-hazardous drains and Closed drains (which are also hazardous). It is important that segregation and interface between the individual drain systems, and between the drain systems and the plant, is managed

As with all MAH process plant, all drawings should accurately reflect the plant; the detail of individual streams, and how they interact with each other, and with process plant, should be clearly detailed. The detail of any protective devices, such as relief orifices to limit gas blow-by, should be evident. Clear drawings will assist with managing change, and this is a complex area for drains where HP/LP interfaces and uses may change. The implications on the drain systems of any changes to the area classification of the installation (Hazardous area zoning) should also be assessed and managed.

Seal pots, seal loops and lute seals in the drain headers are used to provide segregation between drain systems. Seal pots and loop seals can either rely on a continuous or a dedicated water supply, which should maintain all seals liquid full. Routine plant inspections should include checking that seals are intact and that no debris has collected to block drains or gullies. Vents or siphon breakers should be provided at vertical falls to prevent liquid being siphoned out of the seal. Segregation of the drains systems is also necessary at the drains caisson. Dip pipes for the non-hazardous drains should be lower than those for the hazardous drains, to prevent migration of gas. The integrity of the dip pipes should be assured. (The dip pipes may have corroded off or perforated at or above the water line).

Lute seals (U bends) may also be provided on drains tanks, bulk storage tanks, tanks in columns and crane pedestals. These provide a liquid seal to prevent migration of gas between systems. The integrity of these seals should be maintained.

Where drain systems are interconnected directly between vessels, e.g. open drains pumped back to closed drains via dedicated nozzle on closed drains vessel, then it should be ensured that any internal vessel down-comers are of sufficient length such that a liquid seal is maintained under all foreseeable operating conditions. Low level trips should be provided on the downstream vessel and be set at an appropriate level to maintain the liquid seal and prevent reverse flow between systems.

All hazardous drains vessels shall be provided with a vent connection, either to atmosphere or flare, depending on their service. Where atmospheric vents are used it should be ensure that these are located in an appropriate area (hazardous area classification). Drain vessels equipped with atmospheric vents shall also be provided with purge facilities to prevent air ingress.

Winterisation of drain lines (particularly across bridges) and seal loops should be provided to prevent blockage. Winterisation should be maintained in good condition, and its effectiveness assured.

### **Industry Standards and Guidance**

- Norsok Publication P-002, 'Process System Design', First Edition, 2014

### **Relevant HSE guidance**

- HSE Publication L65, 'Prevention of fire and explosion, and emergency response on offshore installations - Approved Code of Practice and Guidance', Third Edition, 2016

### **Inspection Approach**

- Confirm whether there are any interconnections between the platform drains system. If there are, then ensure that they are segregated through an appropriate means
- Where seal arrangements are used to segregate drains system then confirm with operations personnel how they ensure that they remain liquid filled at all times. Confirm whether or not there is a maintenance regime in place.
- For drains vessel where it is essential to maintain a liquid seal to prevent gas migration then ensure that level alarms and trips are set at the right levels.
- Request a copy of the Duty Holder winterisation (heat tracing and insulation) philosophy document and confirm that they have a strategy in place for protection of drain lines from freezing. Carry out a sample of drain lines in field and confirm the defined strategy is in place.
- Identify which drains vessels, if any, have an atmospheric vent route. Ensure that the discharge from the vents are located in an appropriate area and that the vessels are provided with a purge facility to prevent air ingress.

## Matters of Evident Concern

Inspection finding	Examples
Changes to the Hazardous drains system have not been assessed.	<ul style="list-style-type: none"><li>• Vessels containing hazardous plant are drained to the wrong drainage system.</li><li>• There are rogue connections between the hazardous and non-hazardous systems</li><li>• There are paths to the local atmosphere (not a safe location) from the hazardous drains system.</li><li>• Winterisation has not been considered.</li></ul>
Inadequate segregation.	<ul style="list-style-type: none"><li>• Seal pots, loop and lute seals are not maintained liquid full (or there is no way to tell).</li><li>• Routine inspections are not carried out</li></ul>

## G) LEAK MANAGEMENT

### Introduction

All process plant has the potential for losses of containment to occur. A strategy should therefore be in place to manage these. That strategy should be supported by procedures, risk assessments, registers and performance indicators.

### Scope

This section covers the management and control of leaks, seeps and weeps from the hydrocarbon process plant.

### Fundamental Requirements

Where any leaks are small, the associated hazards are deemed to be low (or manageable), and there are operational constraints or other more significant hazards that may be introduced by an immediate response to take the leaking system out of service, Duty Holders may decide to continue to operate for a period with a leak. It is essential however that the risks of doing so are identified, measured and controlled. In many ways this can be viewed as an ORA, but there are some specific considerations.

An essential first step is to ensure that all leaks are identified and subsequently assessed. Leaks need to be reported and managed, even if

they appear in themselves to be of low hazard (e.g. a water system), as inevitably they only ever get worse, and can have higher hazard consequences for surrounding plant, people and equipment.

Key to performing an appropriate hazard analysis is to determine an accurate picture of the condition of the equipment, and the cause of the leak. This needs to be informed by an understanding of the mechanical nature of the equipment, its likely failure mechanisms, and suitable measurement of the deterioration that has allowed the leak to occur. In the case of a leak from a hole in a pipe for example, such measurement could consist of a map of pipe wall thickness measurements surrounding the leak site.

Further to this, it is necessary to understand how the deterioration might progress with time, based on an understanding of the failure mechanism. The more rapid the deterioration, the greater the potential hazard, as the opportunities to detect and intervene before an unacceptable situation develops are reduced. The rate of deterioration may not be fixed. For example a minor, gradually increasing leak from a valve packed gland may suddenly escalate when a fastener on the gland packing hold down plate corrodes through.

Finally the hazard consequences of the leak, under all deterioration modes, needs to be identified and assessed. At the end of the assessment process, it may be decided that the risk of operation with the leak is unacceptable, and it should be taken out of service. It is essential that the status of such equipment is effectively recorded/communicated and put 'beyond use' such that it cannot inadvertently be put back into service.

Where it is determined that the leak may be managed, appropriate control measures should be put in place that reduce the risk to ALARP. Control measures need to be focussed on ensuring that the current status of the leak is known, any deterioration is re-assessed, and appropriate responses to specified levels of deterioration are identified upfront, such that action can be taken before unacceptable levels of hazard occur.

Measures need to be realistic to implement, and responsive enough to the dynamic nature of the level of risk as the leak deteriorates. Suitable additional control measures may include warning signs, barriers, safe secondary containment systems, gas detection systems and regular monitoring regimes, amongst others, and these need to be appropriately documented, communicated, and compliance with them monitored. Operational staff also need to feel empowered to be able to respond and take equipment out of service if necessary, without recourse to significant higher management.

### **Industry Standards and Guidance**

- None

## Relevant HSE Guidance

- HSE Publication L65, 'Prevention of fire and explosion, and emergency response on offshore installations - Approved Code of Practice and Guidance', Third Edition, 2016

## Inspection Approach

- Confirm whether the Duty Holder has a strategy in place for leak management (weeps and seeps) and that they have an accurate record of those present on the installation.
- Verify that all leaks are subject to regular review and monitoring for potential deterioration and that an appropriate level of risk assessment has been carried out. Discuss leak monitoring with operations personnel and confirm that it is being carried out including update of records.
- Visually inspect a sample of identified leaks and confirm that they are suitably identified and that the leak rate is consistent with the information contained within any register

## Matters of Evident Concern

Inspection Finding	Examples
Lack of a policy and procedure for management of leaks	<ul style="list-style-type: none"> <li>• No policy in place to define how leaks are managed.</li> <li>• No procedures in place to determine size of leak, risk assess leaks or define actions required.</li> <li>• No information on cumulative assessment of leaks.</li> </ul>
No definition of leak, weeps and seeps and no assessment of individual leaks.	<ul style="list-style-type: none"> <li>• Definition of leak, weep and seep quantities and rates not present</li> </ul>
Records not maintained, no listing of leaks or their monitoring and review	<ul style="list-style-type: none"> <li>• Inadequate register being maintained</li> </ul>
Monitoring not carried out	<ul style="list-style-type: none"> <li>• Records do not show that routine, risk based inspection of leaks is being carried out</li> </ul>
Leak initiation awareness.	<ul style="list-style-type: none"> <li>• Integrity management results not rolled out to workforce. Little or no awareness of high risk areas No awareness of leak initiation mechanisms.</li> </ul>

<b>Inspection Finding</b>	<b>Examples</b>
Leak escalation not considered	<ul style="list-style-type: none"><li data-bbox="687 253 1326 353">• No risk assessment considering leak escalation mechanisms or plan in event of increase in leak rate.</li></ul>

## **APPENDIX 9 - MONITORING AND REVIEW ARRANGEMENTS**

### **Fundamental Requirements**

As part of its overall SEMS, the duty holder should have systems in place to:

- Regularly monitor compliance with its arrangements for control or mitigation of loss of containment risks, and identify any deficiencies and the reasons for them.
- Periodically audit the effectiveness of its arrangements for control or mitigation of loss of containment risks and identify any weaknesses.
- Investigate losses of containment, and instances where there have been significant demands on barriers designed to prevent losses of containment (near misses), and identify root causes.
- Collect process safety performance indicator data on the effectiveness and 'health' of the loss of containment MAH barriers, and analyse it to determine any weaknesses or trends.
- Identify lessons from the wider process/ MAH industries which have a bearing on how it manages its own loss of containment risks, and similarly, share equivalent learnings from its own monitoring and review processes with others.
- Review the findings arising from monitoring and audit activity, investigations of loss of containment and associated near misses, analysis of process safety performance indicator data, and lessons arising from the wider process / MAH industries, and take actions as necessary to address any deficiencies in its own arrangements.

### **Industry Standards and Guidance**

- OGP Publication No. 456, 'Process Safety – Recommended Practice on Key Performance Indicators'
- OGUK Publication, 'Supplementary Guidance on the RIDDOR Reporting of Hydrocarbon Releases'
- Energy Institute Publication, 'High Level Framework for Process Safety Management - Element 19 Incident reporting and investigation,' and
- Energy Institute Publication, 'High Level Framework for Process Safety Management - Element 20 Audit, assurance, management review and intervention'

### **Relevant HSE Guidance**

- HSE Publication HSG 65, 'Managing for health and safety'
- HSE Publication HSG 254 'Developing process safety indicators'
- HSE Publication L154, 'The Offshore Installations (Offshore Safety Directive)(Safety Case etc) Regulations 2015. Guidance on Regulations', First Edition, 2015

### **A) COMPLIANCE MONITORING**

A programme of monitoring should be in place, which has been designed to check compliance with all of measures that the operator has in place related to loss of containment risk. The frequency and nature of the monitoring should reflect the level of risk associated with each particular risk control system. This should be achieved through a combination of active and reactive measures as appropriate. Examples include:

Monitoring activities	Examples relevant to loss of containment
Collection of data in the form of reports	<ul style="list-style-type: none"> <li>• Process safety performance indicators (e.g. control room alarm frequency data)</li> <li>• HCR Investigation system reports (investigation status, number of actions arising)</li> <li>• Risk control system audit scores and corrective actions</li> </ul>
Periodic examination of documents to check that procedures are being complied with	<ul style="list-style-type: none"> <li>• Operator training / competence records</li> <li>• Plant start-up check-sheets</li> <li>• Isolation and work control certificates</li> <li>• Bolted joint tagging system records</li> <li>• Management of change records</li> <li>• Instrumented system inhibit and override registers</li> </ul>
Systematic inspection of plant and equipment ( <i>often in conjunction with checks of documentation as above</i> )	<ul style="list-style-type: none"> <li>• Checks of LO/LC valve status</li> <li>• Checks of leaks/seeps</li> <li>• Supervisory checks that additional control measures identified through ORAs are in place</li> <li>• Area tours looking for loss of containment risks (e.g. hazard hunts, FLIR camera routines)</li> </ul>

Monitoring activities	Examples relevant to loss of containment
Systematic observation of work and behaviour by supervisors/managers as well as engineers/TAs to assess compliance with procedures	<ul style="list-style-type: none"> <li>• Compliance with non-routine or safety critical task procedures (e.g. start-up)</li> <li>• Supervisory checks that additional control measures identified through ORAs are in place (e.g. additional readings sheets, operator tours)</li> <li>• Supervisory checks of shift/crew handovers</li> <li>• 'Job Stops,' or 'Time out for safety' exercises which assess not just personal safety but also process safety risks associated with a task as it is performed</li> </ul>

Note: that the examples referred to above primarily relate to monitoring of operational controls. Asset condition also makes a major contribution to loss of containment risk, and appropriate monitoring needs to be in place for those measures which contribute to assuring it (such as work equipment inspection and maintenance programmes). Further guidance on inspecting these arrangements is provided in the ED Offshore Intervention Guide **'Inspection of Maintenance Management' in appendix 4 'Effective review.'**

Roles and responsibilities for compliance monitoring should be established in writing. In addition, clear guidance (and where necessary training) should be provided to those carrying out the monitoring so as to explain what is expected. This should cover such matters as:

- How and when the checks should be carried out
- How the observations and findings should be recorded
- How any deficiencies identified should be reported and addressed, perhaps depending on the level of non-compliance or risk identified

Written records should include evidence of which particular piece of equipment, system, procedural element or check sheet has been looked at or person spoken to, so as to provide a supporting audit trail.

Those performing the monitoring should be sufficiently independent of those performing the activity.

### **Inspection approach**

- Review duty holder SEMS and CMAPP (from safety case) for references to monitoring and audit arrangements.
- Request copy of duty holder monitoring programme/plan for the installation which addresses controls relevant to MAH risk. This should include

information on what monitoring checks take place, the frequency of those checks, who performs them, and copies of any checklists/templates used as part of the programme.

- Obtain copies of any procedures which describe the compliance monitoring process and where appropriate discuss with the owner of the process how it is in practice managed.
- Look at the outputs from the monitoring programme in terms of written records, performance scores, corrective actions etc.
- Discuss with those performing the monitoring how effective they feel the process is, and in particular what responses they get from management as to the information collected, and any concerns raised. Do they feel that the monitoring is valued?
- Determine whether the monitoring programme and procedures are being adhered to
- Assess whether the monitoring programme is achieving its objectives, and whether all necessary risk control systems are being sufficiently monitored and deficiencies are being identified.

### Matters of Evident Concern

Inspection finding	Examples
Weak compliance monitoring schedule	<ul style="list-style-type: none"> <li>• No monitoring programme in place</li> <li>• Monitoring programme has been developed over time, in an ad hoc way, and not reviewed for suitability vs a systematic review of the key risk controls in place</li> <li>• Some key risk control measures (e.g. PTW) are not being monitored</li> <li>• Frequency and depth of monitoring not reflective of level of risk</li> </ul>
Those carrying out monitoring are insufficiently independent or competent	<ul style="list-style-type: none"> <li>• Staff involved in carrying out monitoring have not been trained or had clear expectations set as to how to perform the task</li> <li>• Lack of visibility or awareness of staff of monitoring programme</li> <li>• Limited involvement of staff in monitoring programme</li> <li>• Lack of independence of personnel involved in monitoring (e.g. operators monitoring own work or that of peers)</li> </ul>
Ineffective capture and reporting of deficiencies	<ul style="list-style-type: none"> <li>• No (or limited) written records of monitoring activity</li> <li>• Few deficiencies identified by monitoring programme</li> <li>• Limited identification of corrective actions</li> <li>• Corrective actions and monitoring results are not shared with relevant staff (e.g. onshore TAs)</li> </ul>

## **B) PERIODIC AUDIT**

An audit programme should be in place, which looks at both the management system and technical and operational practices. The audit programme should ensure that audits are being carried out on MAH prevention barriers.

Periodic audit should be distinct from compliance monitoring, in that it should assess whether the arrangements for risk control are effective, rather than simply whether they are being adhered to (although clearly the latter needs to be considered as part of this).

Although audits will likely be performed at a lower frequency than the associated compliance monitoring activity, it is important to ensure that they are frequent enough to provide assurance.

Audits should assess the available compliance monitoring data and records to identify any weaknesses, common themes or trends. This should be supplemented by first hand observation of the risk control measures in use and the outputs from these.

In judging effectiveness of the arrangements for risk control, auditors should not just consider the systems as implemented on the installation, but also wider industry good practice for control of similar risks

Audits should also consider whether the compliance monitoring arrangements are sufficient to assure the organisation that the risk control arrangements are being followed (i.e. are the checks the right ones, are they frequent enough, are sufficient records maintained etc.).

Auditors should have a level of independence from those performing the monitoring, and ideally a higher level of expertise or competence in the topic being examined. It is not uncommon for two levels of audit to be performed to achieve such oversight, with the first level being internal to the installation's management structure, and the second higher level being at a wider or corporate level.

Effective arrangements should be in place to capture and report audit findings. Simple scoring mechanisms should be in place to help summarise and communicate performance/risk control measure health, such as traffic lights (red, amber, green), % effectiveness etc.

Arrangements for audit should also be subject to monitoring and review.

### **Inspection approach**

- Review duty holder SEMS and CMAPP (from safety case) for references to monitoring and audit arrangements.
- Request copy of duty holder audit programme/plan for the installation which addresses controls relevant to MAH risk. This should include information on audits are in place, the frequency of the audits, who

performs them, and copies of any checklists/templates/guidance used as part of the programme.

- Obtain copies of any procedures which describe the audit process and where appropriate discuss with the owner of the process how it is in practice managed.
- Look at the outputs from the audit programme in terms of written records, performance scores, corrective actions etc.
- Discuss with those performing the audits how effective they feel the process is
- Assess whether a sufficient level of independence is being achieved, and whether appropriate input from external sources (corporate and industry wide) is being incorporated to ensure comparison of performance against relevant good practice
- Determine whether the audit programme is being adhered to
- Assess whether the audit programme is achieving its objectives, and whether all necessary risk control systems are being sufficiently checked and deficiencies are being identified.

### **Matters of Evident Concern**

<b>Inspection finding</b>	<b>Examples</b>
Audit schedule is weak	<ul style="list-style-type: none"> <li>• No audits in place (reliance on compliance monitoring only)</li> <li>• Audit programme does not cover all risk control measures</li> <li>• Audits are insufficiently frequent</li> </ul>
Audits are insufficiently independent or thorough	<ul style="list-style-type: none"> <li>• Audits are typically carried out by the same set of individuals who perform the compliance monitoring</li> <li>• No audits performed by those external to the local management structure</li> <li>• Auditors do not have sufficient depth of expertise to address the topic adequately</li> </ul>
Poor audit finding capture and reporting	<ul style="list-style-type: none"> <li>• No written audit reports</li> <li>• Poor linkage between compliance monitoring data, audit findings and corrective actions</li> <li>• Lack of simple score or output measure arising from audits</li> </ul>

### **C) INVESTIGATION OF LOSSES OF CONTAINMENT AND NEAR MISSES**

Robust policies and procedures for investigation of HCRs (and significant challenges to containment barriers) should be in place.

Sufficient competent technical resources should be available and allocated to investigate HCRs/near misses and identify any implications for the duty

holder's SEMS. The opportunity should also be provided to elected safety representatives to investigate incidents, either individually or in conjunction with the duty holder's own investigation. Consideration should be given to the required scale and nature of the investigation, including the level of independence of investigators, dependent on the circumstances of the event. Factors which should influence such decisions include:

- The size (and/or potential size) of the release
- The actual (or potential) consequences
- The potential for incident escalation
- The number, scale or nature of any impairments of safety barriers
- The frequency or similarity of any activity associated with the HCR/near miss related to ongoing operations, and hence risk of a repeat (or similar) incident

All investigations should attempt to determine the immediate, underlying and root causes of the incident, and in particular to identify which systems, barriers or procedural controls have failed. Any deficiencies in the design of such systems should be determined, as well as any organisational or management system failing which have led to them.

Specific to HCRs, the total quantity and rate of release of flammable hydrocarbons should be determined.

A variety of methodologies for investigation are available, both duty holder specific or proprietary. The key elements of an investigation should include:

- Collection of evidence, e.g. direct observation, documents, witness interviews
- Assembly and consideration of evidence
- Comparison of findings with legal, industry and company standards
- Identification of failed barriers / systems
- Drawing of conclusions
- Making recommendations for future risk reduction

Evidence should be collected which relates to the potential causes of the incident. This should include (as a minimum) consideration of:

- Job factors (adequacy of workplace precautions, condition and suitability of plant, procedures and systems of work, nature of substances, ergonomics and lighting)
- Personal factors (behaviour, suitability and competence of those involved)
- Management and organisational factors (adequacy of policy, how work is controlled/supervised, co-operation and involvement of staff, competency assurance, fatigue, planning, risk assessment and design of measures, monitoring, review and audit measures)

## Inspection approach

- Obtain and review copies of three most recent, complete HCR investigation reports.
- Obtain and review copies of three most recent, complete LoC barrier challenge (near miss) investigation reports.
- Discuss with installation management their view of the effectiveness of their HCR/near miss investigations
- Discuss with elected safety representatives the extent of their involvement in the investigation of HCRs and associated near misses, and their view of the implementation of corrective actions arising from those investigations
- Assess the quality of the investigations described in the reports and through inputs from duty holder personnel.

## Matters of Evident Concern

Inspection finding	Examples
Arrangements for investigation of HCRs are weak	<ul style="list-style-type: none"><li>• No procedure or policy for investigation of incidents/near misses</li><li>• HCRs (or significant near misses) have not been investigated</li><li>• Investigations of HCRs do not effectively identify causes (underlying or root causes in particular)</li><li>• Investigations do not identify appropriate corrective actions</li><li>• Duty holders do not correctly quantify the size of releases</li><li>• Safety representatives have little (or no) involvement in HCR investigations</li></ul>

## D) PROCESS SAFETY PERFORMANCE INDICATORS

An appropriate set of leading and lagging process safety performance indicators (PSPIs) should be defined for all key MAH barriers relating to loss of containment risk, including both those related to asset and operational integrity.

Operational integrity is about ensuring that effective procedural and managerial controls are in place to control the risk of loss of containment of hydrocarbons from the process plant. It is concerned with how people interact with the process plant and how this may lead to risk. At a high level it is concerned with the process safety culture, leadership and management on the installation. At a more detailed level it considers the suitability of particular procedures (e.g. PTW, isolations, overrides) as well the effectiveness of training, competence assurance, ORAs, management of change etc. It is distinct from asset integrity which is traditionally concerned with ensuring that the physical condition of the process equipment/hardware is sufficiently robust to prevent a loss of containment of hydrocarbons or other potential major

accident hazards (e.g. structural collapse). This would include such topics as mechanical design, materials selection, inspection, maintenance management, ongoing fitness for service assessment, repairs etc.

A systematic, risk based approach should be used to identify which performance indicators should be collected, rather than reliance upon a set which has developed over time. The set of performance indicators should also be subject to regular review to ensure that they remain relevant and useful.

The selected indicators should target the critical elements of each MAH barrier, rather than attempt to measure all aspects of the performance of the barrier as a whole

Indicators should be carefully defined, with clarity provided on:

- What the measure is
- How it is collected (e.g. what records or systems are reviewed)
- How the source data is manipulated or analysed
- Who is responsible for collection and reporting
- The required frequency of collection and reporting
- The timescale over which the data is collected (some indicators will be 'snap-shot' values at a particular moment in time, some may be a total, maximum or average over a period, e.g. shift, week, month)

Target (or action levels) should be set for each indicator, such that it is possible to determine whether the associated risk control element is 'healthy' or otherwise. Simple traffic light or scoring systems should be used to indicate this. Thresholds should also be set for differing levels of management review or escalation depending upon the extent of deviation above the target.

A regular report should be produced for management (but available to all staff) which summarises the current values (as well as any trends in the values) of the indicators, and thus provides an overview of the state of health of the associated barriers. As well as the 'raw' indicator figures, it is helpful if some explanatory text or context can be provided to explain each value, particularly where these are outside of their target. The report should be as simple and visual as possible and ideally no longer than a single page.

The latest indicator report should be discussed as part of regular management reviews at all levels within the organisation. Corrective actions should be identified, recorded and implemented as a result. It is important to note however that a review of the indicators should not drive unwanted behaviours or outcomes, and action taken to correct one indicator above its threshold does not adversely affect the performance of another risk control system. It is important therefore that a 'balanced score card' approach is used to managing the risks and actions arising, and a proper understanding of the reasons why a particular indicator is outside of its control limits is reached, before determining the appropriate action.

A number of process safety performance indicators that may be useful in monitoring the health of the operational systems and barriers associated with prevention of loss of containment are presented below. These are provided as guidance only, and it is important that duty-holders determine and utilise a set of indicators that is relevant to their own assets and safety management systems.

**Sample process safety performance indicators for an offshore installation**

<b>MAH Barrier</b>	<b>PSPI examples</b>
Process Plant construction and commissioning processes	<ul style="list-style-type: none"> <li>• % of incomplete HAZOP actions by risk level</li> <li>• % of required operating instructions which have been issued</li> <li>• % of identified operating technician training in new equipment which is complete</li> <li>• % of identified critical joints which have been passed as fit for service</li> <li>• % of identified critical joints which have failed initial inspection</li> <li>• No. of design changes identified for assessment during each phase (construction, commissioning, early operation)</li> <li>• No. of leaks identified during leak testing (by system)</li> <li>• No. of punch list items by priority</li> </ul>

MAH Barrier	PSPI examples
Process Plant operation within safe limits	<ul style="list-style-type: none"> <li>• No. of occasions safety critical operating parameters are exceeded</li> <li>• No. of demands on safety critical alarms</li> <li>• No. of demands on SIL 1 or above instrumented protective systems</li> <li>• No. of demands on mechanical relief devices</li> <li>• No. of process operating procedures which are beyond their due date for review</li> <li>• No. of safety critical tasks identified but not assessed</li> <li>• No. of incomplete corrective actions arising from safety critical task assessment</li> <li>• No. of safety critical task observation corrective actions identified</li> <li>• % Operating Technicians identified as fully competent</li> <li>• % Completion of technician refresher training programme</li> <li>• No. of control loops in manual mode</li> <li>• No. of control valves physically bypassed</li> <li>• No. of supervisory hours spent 'on plant'</li> <li>• No. of live investigations of process upsets/excursions</li> <li>• No. of live (incomplete) actions arising from process upsets/excursions</li> <li>• No. of control valves which are physically bypassed</li> <li>• No. of control loops which are operated in manual mode</li> <li>• No. of hours that safety critical equipment is not functioning</li> <li>• No. of hours that safety critical equipment is impaired</li> <li>• % P&amp;IDs line walk checked for accuracy in last 3 years</li> <li>• No. of P&amp;ID corrections identified awaiting P&amp;ID update/issue</li> </ul>

MAH Barrier	PSPI examples
Instrumented Protection Systems	<ul style="list-style-type: none"> <li>• No. of current inhibits of instrumented protective systems</li> <li>• Cumulative time that instrumented protective systems have been inhibited</li> <li>• Alarm frequency rate in control room (alarm/operator/hour)</li> <li>• No. of standing alarms (alarmed/accepted but not reset)</li> <li>• No of failures of SIL 1 or above protective systems to meet required performance standard on periodic test</li> </ul>
Relief, Blowdown and Flare systems	<ul style="list-style-type: none"> <li>• % of time that flare knockout drum level is outside of its safe range</li> <li>• % of time that oxygen level in flare/vent system is &gt;10%</li> <li>• No. of occasions of activation of blowdown</li> <li>• No. of systems where blowdown performance standard is not met</li> </ul>
Process Isolation Standards	<ul style="list-style-type: none"> <li>• Isolation standards monitoring audit scores</li> <li>• No. of 'live' baseline standard non-compliant isolation schemes</li> <li>• No. of locked open/locked closed valves out of normal position</li> <li>• No. of 'long term' isolations</li> <li>• No. of mothball isolations</li> </ul>
Permits to Work	<ul style="list-style-type: none"> <li>• PTW monitoring audit scores</li> <li>• No. of PTW issued (or live) per day (average or peak over a set period)</li> </ul>
Small bore tubing, piping and flexible hoses	<ul style="list-style-type: none"> <li>• % completion of routine small bore tubing visual assembly checks</li> <li>• % of technicians with ECITB stage 3 competence records</li> <li>• % of hoses in date periodic inspection</li> </ul>
Management of change	<ul style="list-style-type: none"> <li>• No. of live (incomplete) management of change projects</li> <li>• No. of management of change projects still live (not closed out) &gt;3 months after project implementation</li> <li>• No. of live temporary management of change projects</li> <li>• No. of live ORAs</li> <li>• No of outstanding HAZOP or process hazard review arising actions</li> </ul>

MAH Barrier	PSPI examples
Other Offshore Process Hazards	<ul style="list-style-type: none"> <li>• Average H2S/CO2 level in well streams</li> <li>• Sand monitoring results</li> <li>• Flare header purge flow rates</li> <li>• No. of live leaks/seeps being monitored</li> <li>• No. of live leaks/seeps operating beyond originally targeted repair date</li> <li>• Plant reinstatement monitoring audit compliance scores</li> </ul>
Positive Process Safety Culture and leadership	<ul style="list-style-type: none"> <li>• No. of Senior management/TA installation visits in accordance with visit protocol</li> <li>• No. of improvement actions arising from management visits</li> <li>• Process Safety Audit scores</li> <li>• No. of Process Safety Improvement actions</li> </ul>

### Inspection approach

- Review duty-holder safety case for references to PSPIs.
- Obtain and review copy of three most recent PSPIs reports for the installation/organisation.
- Obtain copies of any procedures/description of the PSPIs process and where appropriate discuss with the owner of the PSPI system how it is in practice managed.
- Obtain copies of any minutes/action logs arising from any meetings which have reviewed the three most recent PSPIs reports
- Discuss with those reviewing PSPI data how effective and useful they feel the process is.
- Assess whether the PSPIs selected adequately target all of the key risk control measures, and in particular consider the operational risk controls sufficiently (as opposed to just looking at hardware/asset condition status)
- Assess whether effective review of the data is taking place, and appropriate corrective actions are being taken.

### Matters of Evident Concern

Inspection finding	Examples
Management arrangements for PSPIs are weak	<ul style="list-style-type: none"> <li>• PSPIs are not collected</li> <li>• Responsibility for collection, analysis and reporting are not clear</li> </ul>
PSPIs do not cover the full spectrum of activities leading to LoC risk	<ul style="list-style-type: none"> <li>• PSPIs focus solely on asset condition measures and do not consider operational risk control as well</li> <li>• Some key risk control measures are excluded</li> </ul>

Inspection finding	Examples
Poor arrangements for management review of PSPIs	<ul style="list-style-type: none"> <li>• PSPIs are ambiguous or not clearly defined</li> <li>• Thresholds for action are not set</li> <li>• PSPI reports are not produced, reviewed or effectively acted upon</li> </ul>

## E) LEARNING AND SHARING

Sharing good practice across industry sectors, and learning and implementing lessons from relevant incidents in other organisations, are important to maintain the currency of corporate knowledge and competence. Arrangements should be in place to:

- Actively seek leak reduction lessons and good practices from others in high hazard industries (peer to peer learning and learning from peer incidents). This should include offshore oil and gas operators both in the UKCS and worldwide, as well as onshore major hazard industries (refining, oil and gas, nuclear etc.) where relevant.
- Identify updates and changes to relevant codes and standards and review these in light of existing operational arrangements.
- Share learning and experience related to control of major hazards throughout the design and operational lifecycle (including such topics as management and supervision of major hazard operations, improving primary containment, competency of key post holders, key performance indicators), including lessons learned from internal incidents, with peers in industry (e.g. such as via Step Change or Oil & Gas UK) and contribute to preparation and revision of related standards and guidance.

### Inspection approach

- Identify whether the duty holder has carried out a review of its operations against the learning from any recent major (external) process safety incidents.
- Identify what changes have been identified as being required to existing management arrangements arising from recent updates to codes and standards.
- Request information on the nature of any participation the duty holder has with industry bodies/forums for sharing of learning and good practice.
- Request information on how learning from recent HCRs or near misses related to significant failings in loss of containment barriers have been shared with industry.

## Matters of Evident Concern

Inspection finding	Examples
Weak arrangements for self-assessment against revised codes/standards or learning from incidents	<ul style="list-style-type: none"> <li>No evidence of self-assessment of management arrangements against findings from worldwide major process safety incidents (e.g. Texas City, Macondo, Longford)</li> <li>No evidence of self-assessment of operational arrangements against changes to codes and standards related to management of loss of containment risks</li> </ul>
Lack of participation in industry learning & sharing initiatives/forums	<ul style="list-style-type: none"> <li>Lack of membership or attendance at relevant industry bodies/forums</li> <li>Failure to share learning arising from loss of containment incidents with industry (e.g. via Step Change Incident Alert Database)</li> </ul>

### F) REVIEW

Appropriate management arrangements should be in place to review the findings arising from:-

- Monitoring and audit activity
- Investigations of loss of containment and associated near misses
- Analysis of process safety performance indicator data
- Learning from wider industry and reviews of updated codes and standards

and take actions as necessary to address any deficiencies. The arrangements should include a review of relevant data and reports within regular management meetings, possibly as agenda items within wider operational meetings or in sessions dedicated to the task. Terms of reference for these meetings should be clearly defined, and records of issues discussed and actions taken maintained.

Corrective actions should be appropriately resourced and timescales set for completion on the basis of risk, with a view across all of the duty holder's operations at a particular installation.

Certain matters arising from the review should be raised to management board level. These include:

- Significant individual matters where there is a high potential for MAH
- Risk issues which are repeating or are substantially overdue previously set targets
- New requirements arising from legislative change, industry guidance or practice, or other change which will need substantial resource or sustained effort to implement

- Wider matters with a cumulative effect which may impact on the organisation's ability to manage and control major accident hazards (such as corrective action backlogs)

Depending upon the maturity and health of a duty-holder's safety management system, it may be appropriate to implement an HCR Improvement plan. This should describe the key improvement activities arising from the review process, and be an effective visible means of communicating priorities and progress across the organisation. The plan should also explain how the improvement will be achieved, through appropriate leadership and engagement, resourcing, training and competence, targets and metrics, revised practices, monitoring and auditing.

### **Inspection approach**

- Obtain latest version of installation/duty holder 'safety improvement plan' or equivalent
- Obtain latest version of installation/duty holder 'HCR improvement plan' or equivalent
- Discuss with duty-holder how findings from monitoring, audit and investigations are managed.
- Obtain summary of number of corrective actions within duty-holder action management systems related to incident investigation, monitoring, audit or PSPI reviews, and associated timescales and assigned priorities/safety criticality.
- Obtain duty holder procedures for prioritising/assessing safety corrective actions
- Determine whether duty holder is meeting own standards for assessing criticality of corrective actions and prioritising accordingly.
- For a selection of high criticality and/or longstanding/overdue actions related to loss of containment risk control, review whether the measures taken and residual risk remains appropriately managed
- Confirm whether duty holder procedures provide guidance on which issues should be raised to manage board level, and look for evidence that this has taken place as appropriate.
- Discuss with a range of staff (including those at senior levels within the organisation in particular) their understanding of which risk control measures are weak, which improvement activities are in place which will help address the deficiencies, and what their role is in helping to deliver this. Assess whether the organisation has a good understanding of the risks, a clear well communicated plan, and staff who are effectively involved and engaged to help deliver improvement.

## Matters of Evident Concern

Inspection finding	Examples
Weak arrangements for review of findings	<ul style="list-style-type: none"><li>• Monitoring, Audit and Investigation findings are not regularly reviewed</li><li>• Management reviews do not identify appropriate/achievable corrective actions</li></ul>
Weak management of corrective actions	<ul style="list-style-type: none"><li>• Significant findings are not escalated to management board level</li><li>• Improvement plans are not sufficiently resourced or achievable</li><li>• There are multiple repeat findings from monitoring/audits/investigations suggesting issues are not being dealt with</li><li>• There are many corrective actions which are incomplete/overdue</li></ul>
Poor communication of improvement plans	<ul style="list-style-type: none"><li>• Areas of weakness, corrective actions and priorities for improvement are not visible/well known across the organisation</li></ul>

## APPENDIX 10 - POSITIVE PROCESS SAFETY CULTURE

### Introduction

The ACSNI Human Factors Study Group identified the safety culture of an organisation as *'the product of individual and group values, attitudes, perceptions, competencies, and patterns of behaviour that determine the commitment to, and the style and proficiency of, an organisation's health and safety management. Organisations with a positive safety culture are characterised by communications founded on mutual trust, by shared perceptions of the importance of safety and by confidence in the efficacy of preventative measures.'*

An organisation with a positive safety culture will typically exhibit the following attributes:

- Visible commitment to safety by management
- Workforce participation and ownership of safety problems and solutions
- Trust between shop floor and management
- Good communication
- Competent workforce

More specifically, the process safety culture of an organisation relates to how effectively matters of process safety management are addressed within the safety culture. Whilst there are many common themes between the two, there are some specific aspects required for a positive process safety culture which are additional to the list above, or of particular importance. These are described in the 'Fundamental Requirements' section below.

### Scope

Effective major accident hazard (MAH) leadership is essential if a positive process safety culture is to be delivered at an installation. For it to be fully effective, it needs to exist throughout the duty holder's organisation, and be driven at board level.

Extensive guidance already exists for inspection of MAH/Process Safety leadership at senior levels within an organisation. This appendix is therefore not intended to repeat this, and instead focusses on offshore inspection of activities and arrangements which have a bearing on the process safety culture at the installation. This will naturally inform a view of the wider organisational culture and arrangements, but remains only a part of the whole picture.

### Fundamental Requirements

The CCPS publication 'Guidelines for Risk based Process Safety' identifies twelve principles which support a positive process safety culture. Key elements of these have been grouped and paraphrased in the four topic areas below:

Area	Principle
Effective process safety leadership	<ul style="list-style-type: none"> <li>• Visible, active, believable, engaging, and consistent support for process safety programmes and objectives exists at all levels of management.</li> <li>• Managers are committed to doing what is right, share their values, and inspire and motivate others through their communications, actions, priorities and provision of resources.</li> </ul>
Process safety is a core value of the organisation, and individuals	<ul style="list-style-type: none"> <li>• Process safety is a core value, shared and understood by all individuals and the organisation as a whole.</li> <li>• Traditional worker personal safety and process safety management are recognised as different, and require alternative approaches</li> <li>• Everyone understand their own responsibilities with respect to the overall process safety performance.</li> </ul>
Process safety management standards are set, performance is monitored, and deficiencies are addressed	<ul style="list-style-type: none"> <li>• There is clarity as to the expected process safety management targets, objectives, processes, and activities</li> <li>• The organisation is alert to the potential for performance degrading over time and should establish effective monitoring and audit regimes</li> <li>• There is strong intolerance for failings of process safety management systems and poor process safety outcomes</li> <li>• Effective actions are taken to address process safety management failings</li> </ul>
There is a chronic sense of unease with respect to major accident hazard risks	<ul style="list-style-type: none"> <li>• A high awareness of process hazards and their potential consequences exists within the organisation</li> <li>• There is constant vigilance for indications of system weaknesses that might allow such hazards to manifest themselves.</li> <li>• The organisation actively seeks to avoid the complacency that can result from past safety successes, and learn from its mistakes and that of others</li> </ul>

### Industry Standards and Guidance

- Energy Institute Publication, 'Guidance on meeting expectations of EI Process Safety management Framework Element 1 Leadership, commitment and responsibility'
- CCPS Publication, 'Guidelines for Risk Based Process Safety'

## Relevant HSE guidance

- HSE Publication, 'PSLG Principles of Process Safety Leadership', available at <http://www.hse.gov.uk/comah/buncefild/pslgprinciples.pdf>
- HSE Publication, 'HSE Human Factors briefing Note 7 Safety Culture', available at <http://www.hse.gov.uk/humanfactors/topics/07culture.pdf>
- HSE Publication, 'HSE Human Factors Inspectors Toolkit Common Topic 4: Safety Culture', available at <http://www.hse.gov.uk/humanfactors/topics/common4.pdf>

## Inspection Approach

- Identify what leadership or onshore staff (e.g. TA) visits have taken place on the installation in the last 12 months, and obtain a summary of the agenda or itinerary for the visits.
- Identify any examples of when the installation has been shut-down as a result of process safety concerns in the last 12 months.
- Identify any recent examples of individuals having been rewarded for good process safety performance.
- Determine whether there is a process safety related improvement plan. If so, is it visible, are people aware of it and involved with it?
- Determine whether there is a set of process safety related standards of behaviour. Is it meaningful, and supportive to individuals carrying out their work?
- Obtain a description of the installation observational safety system. Determine if process safety related concerns are incorporated within it.
- Review the installation noticeboards for process safety related content. Is there evidence that process safety matters have a high profile?
- Review the management control and reporting systems for the installation (regular meetings structure, attendees, outputs etc), and attend any key meetings, including SI971 safety committee meetings. Are Process Safety/MAH matters proactively discussed?
- Obtain a copy of any recent process safety related incidents that had been investigated. Is there a good level of understanding amongst the workforce of the root causes and corrective actions?
- Discuss with safety representatives their understanding and involvement with process safety matters. Have they received specific training on the safety case? Have they received the OPITO training module for safety reps on MAH hazards (or an equivalent)? Have staff attended practical MAH awareness sessions (such as at a test facility)?
- Identify whether process safety learnings and best practises from other installations, operators, industries are routinely discussed, and in what forums.
- Discuss with a cross section of the workforce what they understand process safety is and the role they individually play in preventing a MAH

## Matters of Evident Concern

Inspection finding	Examples
There is weak senior management process safety leadership seen on the installation	<ul style="list-style-type: none"> <li>• Senior managers rarely visit the installation, and when they do, are not involved in discussions or activity related to MAH management</li> <li>• Deficiencies in process safety management are tolerated, and there is a lack of a well-publicised and resourced improvement plan</li> </ul>
There is a lack of clarity of roles and responsibilities, and expectations of behaviour and performance for process safety management on the installation	<ul style="list-style-type: none"> <li>• Staff do not understand which activities that they undertake which have the greatest impact on MAH risk</li> <li>• Required process safety behaviours are not defined or communicated in an understandable form</li> <li>• Individual performance contracts/appraisals/job descriptions do not contain any explicit process safety related objectives or responsibilities</li> </ul>
Monitoring systems for process safety management systems are weak	<ul style="list-style-type: none"> <li>• No monitoring programme is in place</li> <li>• Some key risk control measures (e.g. PTW) are not being monitored</li> <li>• Frequency and depth of monitoring is not reflective of level of risk</li> <li>• No (or limited) written records of monitoring activity</li> <li>• Staff involved in carrying out monitoring have not been trained or had clear expectations set as to how to perform the task</li> <li>• Lack of visibility, awareness or involvement of staff in monitoring programme</li> <li>• Few deficiencies identified by monitoring programme</li> </ul>
Arrangements to ensure understanding of installation MAH scenarios, their initiating events, consequences and preventative barriers by the workforce are weak	<ul style="list-style-type: none"> <li>• Staff are provided with limited MAH awareness training</li> <li>• Staff are unfamiliar with the installation safety case or have never looked at it</li> </ul>

Inspection finding	Examples
Workforce engagement on process safety matters is weak	<ul style="list-style-type: none"> <li>• Elected safety reps rarely discuss process safety matters as part of their meetings (and in particular any proactive or leading indicators of risk)</li> <li>• Elected safety reps are not involved with investigation of HCRs, MAH related events or other related near misses</li> <li>• Staff are not involved in process safety related improvement teams or activity</li> </ul>

### Examples of good practice

Expected process safety behaviours (at all levels and job roles within the organisation) are documented and regularly communicated, for example in a safety policy which is displayed on installation notice boards, and via regular communications (e.g. town halls and briefings, and installation inductions), and as part of staff appraisals.

Leadership take highly visible action to stop production when process safety is compromised, and explain their reasons.

Leadership publicly praise/reward individuals who show exemplary process safety behaviour (including shutting down production in response to warning signs, even if it subsequently found that there was not a significant risk).

Targets and standards for process safety performance are set, publicised and regularly reported upon with an explanatory commentary. These have a bias towards input (leading) rather than output (lagging) measures.

Monitoring and audit systems for MAH risk control systems are highly visible and supported. Findings are regularly communicated and discussed, and improvement actions and plans shared.

Process Safety Observational systems (analogous to behavioural safety observational systems e.g. STOP) are used.

Process safety hazards, addressed as part of the original installation design basis and safety case, are periodically reviewed to ensure that the controls remain appropriate, are still in place as intended, and staff have a good understanding of the reasons for them.

Senior leaders carry out installation visits, and discuss major hazard risks. There is written guidance which defines the expectations and behaviours for such visits in terms of their frequency, content and purpose, which supports leaders in asking appropriate questions, giving key messages, and ensuring

consistency. Activities carried out during such visits should help to promote trust, and support a positive process safety culture.

These may include (for example):

- Carrying out safety observations/conversations with front line workers
- Reviewing recent incident investigations and discussing findings/corrective actions with staff
- Auditing operational risk control systems such as Permit to Work, Safe isolations etc
- Verifying the status of SECE maintenance
- Reviewing progress with the hydrocarbon release reduction programme
- Inspecting the condition of process plant
- Discussions with safety representatives

All employees are provided with MAH awareness training. As well as providing an understanding of the generic hazards present on an offshore installation, the MAH scenarios and controls specific to the installation are also covered. Training makes clear what each individual or job role is required to know or do to control each MAH risk. Staff have the opportunity to witness practical demonstrations of MAH scenarios such as vapour cloud explosions, jet fire etc at a test facility. Safety representatives in particular are also provided with the opportunity to receive MAH awareness training, such as that provided by OPITO.

The safety case is readily accessible to the workforce and appropriate training is provided to all staff so they can easily understand it.

Learning from incidents and best practices arising from the process industries (not just from within the same company or UK offshore industry) are regularly shared with the workforce.

## **APPENDIX 11 - FLOATING PRODUCTION, STORAGE AND OFFLOADING (FPSO) INSTALLATIONS**

### **Introduction**

Floating Offshore Platforms can be grouped into the following categories:

- Production
- Storage and/or Offloading
- Drilling and Production
- Production, Storage and Offloading (FPSO)
- Drilling, Production, Storage and Offloading

There are several types of floating structure which fit into the context listed above and can be converted tankers or purpose built structures:

- Monohull (ship-shaped structures and barges)
- Multi-hull semi-submersibles
- Cylindrical shaped production spar.

In this guide, the main consideration will be for a monohull, ship-shaped floating structure. An FPSO system is an offshore production facility that stores crude oil in tanks located in the hull of the vessel. The crude oil is periodically offloaded to shuttle tankers for transport to shore. FPSO's may be used as production facilities to develop marginal oil fields or fields in deep-water areas remote from the existing main export pipeline infrastructure.

Optimum storage capacity on an FPSO will be site specific and a function of; export parcel size, production throughput, frequency of cargo offloading, the available weather window and the duration of weather interruptions.

The main potential loss of containment hazards for an FPSO includes:

- Change in actual process conditions from outside of the design envelope
- Leaks emanating from the riser/turret/ swivel systems for FPSO hydrocarbon loading
- Hull stresses and vessel motion (weather and equipment induced) whilst loading and discharging hydrocarbons
- Corrosion / fatigue mechanisms within the FPSO processing facilities and cargo tanks
- Inadequate venting of cargo tanks
- Leaks arising from offloading operations, including ship to ship, mooring collision and hose malfunction.
- Dropped loads onto the process deck
- Vessel collision
- Inability to drain process fluids due to the FPSO movement.

## Scope

This guide specifically covers ship-shaped monohull floating structures. This inspection guidance applies to areas and situations on an FPSO that could potentially lead to a Loss of Containment and what systems should be in place to prevent, detect and mitigate against a Major Accident Hazard (MAH) from subsequently occurring. The inspection guide will not cover all operating procedures on an FPSO. The scope will cover from the Subsea Isolation Valve (SSIV) to the offloading connection point with the downstream facility (support tanker or onshore facility).

For marine based issues associated with FPSOs, then refer to HID Offshore Inspection Guide – Inspection of Maritime Integrity (Loss of Stability and Position).

## A) OVER AND UNDER PRESSURE PROTECTION

### Fundamental Requirements

Causes of over-pressure and under-pressure should be assessed for topsides in the design phase of the FPSO and the governing cases accounted for. The design for blowdown and relieving facilities associated with the process topsides of an FPSO should be in accordance with API 521 or a similar standard as per fixed installation design. See HID Offshore Inspection Guide for Loss of Containment – Relief, Blowdown and Flare Systems for system inspection requirements.

Where there have been multiple contractors for the topsides PAUs, skids and modules, a flare and relief document should be available to ensure that the complete system relief and blowdown design is adequate for the worst-case conditions.

The FPSO will have a number of pressure relieving facilities on board such as:

- Relief valves for protection against over pressure (for topsides production facilities)
- Pressure and vacuum arrangements (storage tanks)

With regards to the flare header systems on an FPSO, consideration must be given to the roll and pitch of the vessel in severe weather conditions as to whether the vent systems can adequately drain to the flare KO drum. The trim of the vessel (to assist in deck water run-off) should also be considered for drain lines to ensure adequate drainage to the correct location (i.e. separator to flare KO drum).

Safety device philosophies should be in place to cover the following scenarios:

- Closure of the liquid loading line(s) if high pressure is detected in the tank.

- Closure of the inert gas supply valve if high pressure is detected in the header.
- Stopping of the offloading pump(s) if low pressure is detected in the tank.
- Stopping of the VOC recovery system if low pressure is detected in the header.

IG systems are used on FPSOs to inert the vapour space in the storage tanks. In some cases a hydrocarbon blanketing system may be used but a back-up IG system must also be supplied. SOLAS (1974) Regulations (Chapter II-2, Regulation 62) specify the necessary requirements for inert gas and venting systems in order to prevent over/under pressure as well as to prevent the accumulation of an explosive atmosphere in the storage tank head space. There are several requirements of SOLAS Regulations:

- The IG system must be capable of achieving a discharge flowrate of at least 125%v/v of the maximum rated capacity of the cargo pumps achieving a positive pressure at the tank. This should be achieved by at least two blowers. The normal discharge pressure is 0.12 barg.
- The oxygen content in the IG should be less than 5%v/v and a suitable method of monitoring and alerting should be included on the installation.
- At least two non-return device/systems must be present to prevent the backflow of hydrocarbon vapours to the deck machinery spaces. One of these should be a water seal (main deck located) and the other should be located just downstream of the water seal (can be a mechanical, manual isolation valve).
- Alarms should be provided to indicate the following; high oxygen content in the IG main (normally >5%v/v); low gas pressure in the IG main; low pressure in the supply to the deck water seal (if this is installed) as well as a low water level in the deck seal; high temperature of the IG in the main; low water pressure to the IG scrubber.
- A gas regulating valve normally controls the flow of the inert gas from the scrubber to the storage tanks and should close if any of the events listed in the previous bullet are met as well as if the IG blowers fail.
- The Duty Holder should have guidance in place for what weather conditions that venting from the cargo tanks can take place. Generally, venting should only take place when the wind speed is  $\geq 2\text{m/s}$ .
- Any free-flowing vents must be at least 6m above the main deck and at least 10m away horizontally from any open air intakes. These vents must contain flame arrestors to ensure that flashback cannot occur into the storage tank.
- High velocity vents should extend to at least 2m above the cargo tank deck and be located at least 10m away from air intakes. The high velocity vents do not require flame arrestors as the exit speed of the gases is  $\geq 30\text{m/s}$  and estimated to be twice the speed of the flame front.
- The vents should also have associated fire detection and snuffing systems.

Generally, one, or two pressure/vacuum valves will be connected to the main crude oil vent header from the storage tanks which allow the tanks to breathe

(normally between 0.2kg/cm<sup>2</sup> above atmospheric pressure and 0.07kg/cm<sup>2</sup> below atmospheric pressure). These integrated valve sets operate automatically but there must be procedures in place for testing these valves and systems in place to ensure that venting can take place in the event of the pressure/vacuum valve failure.

An emergency pressure/vacuum breaker should be installed in the event of the main pressure/vacuum valve failing, or failing to relieve at the appropriate rate. The PV breaker is a safety critical element and therefore should be subject to routine testing and maintenance. This equipment should be sized for the largest possible overpressure scenario for the cargo tanks.

To reduce the VOC emissions via the vents, a hydrocarbon blanketing and recovery system could be used. The Duty Holder must have procedures in place to ensure that the IG system is both available and switched to the duty system in the event that the HC blanketing is unavailable. Secondary measures must also be in place should the system switch fail (i.e. shut-down of plant).

Use of a HC blanketing/recovery system may also result in no flaring on the FPSO. Unless the flare is continuously lit, the Duty Holder must have a procedure for lighting the flare in the event of an overpressure occurrence. As the route to flare could potentially be closed off with a HC blanketing/recovery system, then a fail-safe method must be in place to provide a route to the flare and prevent overpressure of the equipment.

### **Industry Standards and Guidance**

- API Standard 521, 'Pressure-relieving and Depressuring Systems', Sixth Edition, 2014
- API RP 2FPS, 'Planning, Design and Construction Floating Production Systems', Second Edition, 2011
- International Convention of the Safety of Life at Sea (SOLAS), 1974

### **Relevant HSE guidance**

- HSE Publication L65, 'Prevention of fire and explosion, and emergency response on offshore installations - Approved Code of Practice and Guidance', Third Edition, 2016
- HSE Publication, 'HSE Offshore Information Sheet No. 2/2010 – Reducing the risks of hazardous accumulations of flammable/ toxic gases in tanks and voids adjacent to cargo tanks on FPSO and FSU installations', available at <http://www.hse.gov.uk/offshore/infosheets/is2-2010.htm>

### **Inspection approach**

- Confirm that the duty holder has operating procedures in place for cargo venting operations.
- Confirm that the duty holder has a policy or procedure in place for venting during low wind conditions.

- Confirm with the duty holder (onshore and offshore) what the appropriate action would be under extreme environmental conditions which could affect the draining of the vent headers and associated vessels.
- Confirm that the pressure/vacuum breakers are included as safety critical elements and have an appropriate performance standard.
- Verify that the IG system is capable of achieving a discharge flowrate of at least 125%v/v of the maximum rated capacity of the cargo pumps. **NOTE that this may be assessed by the Maritime integrity discipline.**
- Verify that there is a method of monitoring the oxygen content associated with the inert gas system and that alarms are set at the appropriate levels. Confirm what the operator response would be to the high oxygen content in the inert gas stream. **NOTE that this may be assessed by the Maritime integrity discipline.**

### Matters of Evident Concern

Inspection finding	Examples
The relief device function is impaired	<ul style="list-style-type: none"> <li>• Inappropriate levels or density of fluid mix in the PV breakers.</li> <li>• Vent headers and/or flare KO drum not draining correctly and increasing back pressure on relief device.</li> </ul>
Drainage of vent headers and/or flare KO drum is impaired.	<ul style="list-style-type: none"> <li>• Design and/or installation has not taken in to account the environmental conditions.</li> <li>• Commissioning of the pipework and equipment has failed to identify incorrect drainage of headers or vessels.</li> </ul>

## B) CARGO TANK OPERATIONS

### Fundamental Requirements

Crude oil washing in the storage tanks is mandatory for compliance with International Convention for Prevention of Pollution from Ships, Regulation 13 (MARPOL 73/78). This involves re-circulating dry, crude oil back to the storage tank through a spray nozzle during offloading operations. This could be every offloading process or on a reduced frequency. The dry crude oil will prevent static build-up within the cargo storage tanks.

The Duty Holder must ensure that there are systems in place to prevent the formation of a flammable atmosphere in the storage tanks, which are most likely to be caused from incorrect process isolations for concurrent operations on storage tanks. The processes are usually very operator intensive and require strict safe systems of work to ensure that the correct tanks are isolated and that normal operation of other tanks is not compromised. The operators must be clear about the hazards and consequences associated with

these tasks. For the relevant tank isolations then it is recommended that DBB or removable spools are used.

There can be several IG vent headers associated with crude oil washing and gas freeing:

- Clean gas inert header: used for initial inerting of gas free tanks prior to introducing oil.
- Dirty Inert gas header: used to vent inert gas from tanks during loading and to fill the tanks with IG during offloading and crude oil washing.
- Crude oil tank purge header: used with the clean inert gas header system to vent the tank contents during initial inerting operations and when the tanks are being gas freed.

Appropriate safe systems of work must be in place to ensure that the appropriate vessel is lined up and that there is positive IG supply to the vessel for crude oil washing, which is a routine operation. Note that isolations (including LO/LC valves) around the Cargo tank should also be appropriately marked on the installation and checked against the P&ID for consistency.

### **Industry Standards and Guidance**

- International Convention for the Prevention of Pollution from Ships (MARPOL), 1978

### **Relevant HSE guidance**

- HSE Publication L65, 'Prevention of fire and explosion, and emergency response on offshore installations - Approved Code of Practice and Guidance', Third Edition, 2016
- HSE Publication L22, 'Safe Use of Work Equipment – Approved Code of Practice and guidance', Fourth Edition, 2014
- HSE Publication HSG250, 'Guidance on Permit-to-Work systems – A guide for the petroleum, chemical and allied industries', First Edition, 2005
- HSE Publication HSG253, 'The safe isolation of plant and equipment', Second Edition, 2006

### **Inspection Approach**

- Confirm that the duty holder has a procedure in place for cargo tank operations, which should include relevant hazards which could affect the operator. Any safety critical steps should be clearly identified in the procedure.

## Matters of Evident Concern

Inspection finding	Examples
No appropriate procedures in place for tank cargo operations.	<ul style="list-style-type: none"> <li>• Duty holder classes operation as routine and not provided procedure for task.</li> <li>• Procedures are generic and do not include safety critical steps.</li> <li>• Procedures have not been updated to reflect latest plant operating conditions or configuration.</li> <li>• No appropriate MoC process in place for updating procedures.</li> </ul>
No risk assessments in place for cargo operations.	<ul style="list-style-type: none"> <li>• Hazards, risks and associated hazards are included within an operating procedure.</li> <li>• Duty holder failed to create and implement risk assessment for cargo tank operations.</li> <li>• Appropriate hazards, risks, controls and consequences have not been identified by the duty holder.</li> </ul>

### C) OFFLOADING OPERATIONS

#### Fundamental Requirements

The Duty Holder should have a hose inspection and testing policy/procedure in place to ensure containment when offloading. Potential loss of containment in the hoses could occur from:

- Impact of the hose with the deck (which is increased when the hose is full of liquid)
- Potential corrosion of the hose liners
- Kinking of the hose
- Momentum shock in the hose due to shutdowns, akin to water hammer
- Other hose ageing mechanisms

Green line systems allow for a permit to pump signal (for the FPSO storage tank offloading/export pump) to be sent from the shuttle tanker to the FPSO during tandem offloading once the process and mechanical configuration on the shuttle tanker is aligned correctly.

Appropriate shut-offs should be included in order to minimise any hydrocarbon loss in the offloading lines. This should be in the case of hose/pipe rupture or in the event that the shuttle tanker moves off position and hose disconnection occurs. The oil offloading and transfer system pipework covers the whole area of the main deck and contains a large quantity of hydrocarbon that may be released in any location. Shut-offs could include

manual isolation, remote shut-off valves, shut-down of cargo pumps and/or breakaway couplings. The Duty Holder must have procedures in place for maintaining the shut-down equipment, including the hose shut-off mechanism.

The diameter of the hose string should be in line with the design offloading rate as to not exceed manufacturers fluid velocity limits.

After offloading, adequate capacity of nitrogen or inert gas should be available to displace the offloading hose to assist in its recovery. Liquid in the hose adds extra weight and increased wear on hose and pull-in equipment. Inspection of the offloading hoses for signs of wear and deformation should be routinely carried out.

### **Industry Standards and Guidance**

- Energy Institute Publication, 'Guidelines for the Management of Flexible Hose Assemblies', Second Edition, 2011

### **Relevant HSE guidance**

- HSE Publication L65, 'Prevention of fire and explosion, and emergency response on offshore installations - Approved Code of Practice and Guidance', Third Edition, 2016

### **Inspection Approach**

- Confirm that the duty holder has a procedure or process in place for inspection hoses associated with offloading (or for hydrocarbon/hazardous inventory).
- Inspect the hoses to ensure that they have appropriate markings for identification such that the risks of inspecting the wrong hoses are minimised.
- Confirm that the offloading hoses for hazardous inventory are suitable for operation, i.e. no kinks or corrosion etc.
- Confirm that the location of the hoses would not impact upon any hydrocarbon or hazardous systems, i.e. dropped object or impact potential.
- Confirm what isolations (and other safety systems) are in place for offloading to ensure limited release of hydrocarbon in the event of a loss of containment event.

## Matters of Evident Concern

Inspection finding	Examples
<p>No inspection records of offloading hoses.</p>	<ul style="list-style-type: none"> <li>• Duty holder does not have procedure or processes for inspection of hoses.</li> <li>• Hoses are not captured on the maintenance management system.</li> <li>• Maintenance and/or inspection of hoses devices have been deferred.</li> <li>• Hoses do not have appropriate markings to ensure appropriate inspection.</li> <li>• Hoses are inspected by a third party contractor and not available offshore.</li> </ul>
<p>No appropriate isolation for limiting escape of hydrocarbons in the event of a loss of containment scenario.</p>	<ul style="list-style-type: none"> <li>• Isolation is not appropriate to limit hydrocarbon release in the event of loss of containment event.</li> <li>• No additional risk assessment to cover non-compliant isolation.</li> <li>• Operator interaction required (manual or remote intervention) where operators do not have appropriate experience or training to do so.</li> <li>• No hazard analysis of offloading loss of containment event carried out by duty holder.</li> </ul>

## **APPENDIX 12 - MANAGEMENT OF SMALL BORE TUBING, PIPING AND FLEXIBLE HOSES**

### **Management systems for small bore tubing**

- The use of small bore tubing should be avoided where possible.
- The integrity of small bore tubing system should be addressed within the management system over its whole life cycle. Responsibility for carrying out policy should be allocated to technical authorities within the management system, and monitoring of the implementation of the policy included within the Technical Audit programme.
- An asset register of all small bore tubing systems should be maintained.
- Duty holders should have a formal scheme which ensures that all the personnel (company and contractor) required to work on small bore tubing systems are formally assessed as being competent to do so, including periodic reassessment.
- Management procedures should ensure that Vendor personnel employed on short term construction or maintenance work are competent to carry out such work
- A control and standardisation policy for the technical management and minimisation of small-bore tubing and fittings types should be developed, documented and implemented for each new and existing installation. This should include:
  - Preferred fitting and tube types per plant
  - The fitting and tube type per system or sub system
  - The planned fitting and tube type migration per system or sub-system
  - The strategy to minimise the inventory by design-out, refurbishment and ad-hoc maintenance activities
  - A company or installation directive for new and replacement systems to comply with the preferred equipment requirement
  - Systems to ensure vendor compliance with the policy
- On installations where several makes and types of tubing and fittings are already present, it may not be reasonably practicable to change all systems. In this case it should be demonstrated however that the range of fittings and tubes have been minimised to a manageable level, and that personnel competencies are consistent with the residual inventory.

### **Small bore tubing maintenance and operational procedures**

- Procedures should be available which include how to carry out:
  - Checks of the overall integrity of the system
  - Visual inspection of compression fittings for correct component selection and correct make-up (with use of manufacturer's gauge as applicable)
  - Sample disassembly of compression fittings to check for correct make-up, tube penetration and internal corrosion of tube and clamp
  - Examination of support and mounting for vibration control
  - Check to identify possible problems with maintainability, i.e. access, corrosion, ease of removal etc.

- Response to process leakage or seepage from compression joints and pipe thread connections
- Pressure/leak testing of systems which have been subject to extensive disconnection or involves the installation of untested fabrication equipment, as well as individual impulse lines which have been subject to minor disconnection
- Adjustment and rework should not be permitted on systems whilst pressurised or not adequately isolated
- It should not be permissible to interchange sub-components of different designs or types of fittings
- The installation and assembly of particular types of small bore tubing and fittings must be made in accordance with the manufacturer's instructions. (Note: these can be different between manufacturers and between fitting sizes of the same manufacturer)
- It is essential that fitting is inspected on completion using gauges where available or by other methods recommended by the manufacturers
- Appropriate tools should be defined and used and special tools, such as hydraulic swaging machine should be considered for fittings of larger sizes of fittings and tubing.

### **Vibration and supporting of small bore tubing**

- The Duty Holder should have a structured assessment methodology in place for identification and management of vibration related risk to small bore tubing. Systems with the following possible excitation mechanisms should be identified:
  - Flow induced turbulence
  - High frequency excitation
  - Mechanical excitation
  - Pulsation
- Systems identified to have a problem should be further analysed to determine the likelihood of failure. Where this is significant, the features of the small bore pipe and its connection to the main pipe should be reviewed, and where possible changes made to the design to reduce the risk. Important features include
  - Type of fitting (i.e. weldolet, contoured body, short contoured body etc.)
  - Length of branch
  - Type of fitting (i.e. weldolet, contoured body, short contoured body etc.)
  - Number and sizes of valves
  - Main and small bore pipe wall thickness (schedule)
  - Small bore connection diameter
  - Location of small bore pipe on the main pipe.
- Potential design solutions include:
  - Reducing the overall and unsupported length of the fitting
  - Reducing the mass of unsupported valves / instruments
  - Ensuring the mass at the free end of a cantilever pipe assembly is supported in both directions perpendicular to axis of the small bore

- Arranging supports from the main pipe, to ensure that the small bore connection moves with the parent pipe
  - Maximising the diameter of small bore connections
- Tube support should be provided as per manufacturer's instructions to prevent unacceptable stresses on fittings e.g. eliminate sagging and vibration.
- Valves, gauges etc. should be independently mounted. Expansion loops should be provided as per design. Tube support material should be as per design specification.
- Tube systems should be adequately supported as necessary when connections are being tightened or uncoupled

### **Isolation practices and standards**

A primary isolation valve (piping standard) should be located close to the pipe or vessel, and be to the same standard of pressure integrity. Instrument connections beyond the primary isolation facility are sometimes less robust than the primary connection e.g. compression fitting may be used in the impulse tubing and the instrument may use components such as flexible hoses or sight glasses.

Instruments will generally be provided with local isolation facilities that, together with the primary isolation, can provide a double block and bleed isolation. Drain, vent and test points should be provided with valves to close them off when not in use.

### **Management of flexible hoses**

- The use of flexible hoses should be avoided where possible, in preference to permanent hard-piped systems.
- Duty Holders should ensure that integrity of small bore flexible hoses used on hydrocarbon/ hazardous processing plant is addressed within their management system. Elements should include consideration of design, risk assessment, construction, installation, commissioning, operation, maintenance, testing, modification and decommissioning.
- An asset register of flexible hoses should be maintained.
- Persons responsible for hose section, maintenance or use should be suitably competent and aware of safety critical factors affecting hose integrity though an understanding of hose constructional elements and their function in maintaining integrity, failure modes, failure criteria etc.
- Hose assemblies should only be used in hazardous duties where permanent piped solutions are not suitable or do not offer a safer alternative solution. Hoses should be classified according to the consequence of failure.
- When deciding upon the performance and safe operational requirement of a hose, parameters for consideration include:
  - compatibility of inner liner material with the media to be carried
  - compatibility of outer cover with working environment
  - flow requirements
  - pressure and temperature range

- the operational environment - length, flexibility and bend radius
- weight, compactness and support requirements
- volumetric expansion, movement under loading
- compatibility of hose with end fittings, and fitting compatibility with media and operational environment
- All hoses in critical service applications should be examined on a regular basis, to assess their suitability for continued service. Inspection frequency and criteria should be developed from the risk assessment derived from the classification process.
- Hoses and their fittings should be visually examined for physical damage against defined criteria including:
  - Blisters or bulges
  - Looseness of the outer cover
  - Excessive softening or hardening of the hose (any of these three points may indicate fractured or displaced reinforcement or a leaking liner)
  - Kinks, twists (poor installation)
  - Abrasion, cuts, excessive elongation under load or test
  - End coupling integrity
- Any hose exhibiting cover cracks, cuts or bulges should be removed from service, examined and retested as necessary. Any hose with reinforcement exposed should be removed from service and replaced if extent of damage exceeds manufacturer recommended limits. If in doubt, hoses displaying visible faults should be replaced.
- Pressure testing should be carried out in compliance with relevant vendor's procedure. Records of visual examination should be kept, recording the condition of the hose on a particular date and the date of next inspection. The hose should be tagged with the latest inspection date and the date of next inspection.

### **Industry Standards and Guidance**

- Energy Institute Publication, 'Guidelines for the Management of Flexible Hose Assemblies', Second Edition, 2011
- Energy Institute Publication, 'Guidelines for the design, installation and management of small bore tubing assemblies', Second Edition, 2013
- Energy Institute Publication, 'Guidelines for the avoidance of vibration induced fatigue failure in process pipework', Second Edition, 2008

### **Relevant HSE Guidance**

- HSE Publication L22, 'Safe use of work equipment – Approved Code of Practice and guidance', Fourth Edition, 2014
- HSE Publication L65, 'Prevention of fire and explosion, and emergency response on offshore installations - Approved Code of Practice and Guidance', Third Edition, 2016

### **Inspection Approach**

- Verify whether or not the Duty Holder as an inspection strategy in place for SBT assemblies. Confirm whether or not this has been prepared on a risk based approach, e.g. hydrocarbon containing SBT deemed higher priority
- Identify who is responsible offshore for the inspection of SBT and discuss the current status. Confirm that SBT inspection is taking place at the frequency defined by the inspection strategy.
- Confirm who is responsible for installation or repair of SBT assemblies and that they have received appropriate training.
- Ensure that all SBT is stored in a suitable area and that different types of SBT, e.g. imperial or metric, are segregated. SBT storage arrangements should also ensure that it is protected from any form of damage.
- Conduct a sample check of SBT in-field with a focus on high risk systems, e.g. gas compression, and identify whether there are any at-risk assemblies.
- Verify whether or not the Duty Holder as an inspection strategy in place for flexible hoses and confirm who carries it out.
- Review the installation flexible hose register (where available) and confirm that it accurately reflects the hoses in use on the installation. Particular focus should be on those hoses identified as being out of certification.
- Confirm whether or not there are any flexible hoses in hazardous duty, i.e. hydrocarbon service or high pressure. Inspect these hoses in field and confirm that they are suitably identified and are not exhibiting any signs of wear or damage.
- Confirm with the Duty Holder what their approach is for the quarantine of those hoses which are found to be damaged or out of certification.

### Matters of Evident Concern

Inspection Finding	Examples
Ineffective SBT inspection and management	<ul style="list-style-type: none"> <li>• No risk based inspection programme in place for SBT assemblies</li> <li>• No records available for inspection of SBT</li> <li>• Evidence of incorrect SBT assemblies</li> <li>• Storage arrangements are not available for SBT or no segregation of SBT</li> </ul>
Absence of training	<ul style="list-style-type: none"> <li>• Personnel responsible for installation and repair of SBT assemblies have not received appropriate training</li> <li>• Installation and repair of SBT assemblies is being carried out by those other than those deemed competent</li> </ul>

<b>Inspection Finding</b>	<b>Examples</b>
Ineffective management of flexible hoses	<ul style="list-style-type: none"><li>• No inspection programme in place for flexible hoses</li><li>• Duty Holder does not have a hose register in place</li><li>• Evidence of damaged hoses in hazardous service</li><li>• Flexible hoses are not suitably tagged or identified</li></ul>

## **APPENDIX 13 - DUTY HOLDER PERFORMANCE ASSESSMENT**

When inspecting Loss of Containment related systems there are two areas to be considered as follows:

- 1 When inspecting the outputs from the systems, a decision will have to be reached on whether the risk control measures implemented led to compliance with the relevant legislation. This decision will be made in the same way as for other inspection topics by comparing the standard of control achieved against the relevant benchmarks and applying the principles of EMM.
- 2 The inspection will reach conclusions on overall effectiveness of the duty holder's systems. These should be recorded using the assessment criteria listed below. Those duty holders who either do not have systems, or have system that are substantially ineffective will fall in the very poor or unacceptable categories. Where systems are in place and there is evidence of a number of examples where it results in controls that are ineffective or inappropriate it will fall in the poor category.

<b>EMM RISK GAP</b>					
<b>EXTREME</b>	<b>SUBSTANTIAL</b>	<b>MODERATE</b>	<b>NOMINAL</b>	<b>NONE</b>	<b>NONE</b>
<b>TOPIC PERFORMANCE SCORE</b>					
<b>60</b>	<b>50</b>	<b>40</b>	<b>30</b>	<b>20</b>	<b>10</b>
<b>Unacceptable</b>	<b>Very Poor</b>	<b>Poor</b>	<b>Broadly Compliant</b>	<b>Fully Compliant</b>	<b>Exemplary</b>
<p>Unacceptably far below relevant minimum legal requirements.</p> <p>Most success criteria are not met.</p> <p>Degree of non-compliance extreme and widespread.</p> <p>Failure to recognise issues, their significance, and to demonstrate adequate commitment to take remedial action.</p>	<p>Substantially below the relevant minimum legal requirements.</p> <p>Many success criteria are not fully met.</p> <p>Degree of non-compliance substantial. Failures not recognised, with limited commitment to take remedial action.</p>	<p>Significantly below the relevant minimum legal requirements.</p> <p>Several success criteria are not fully met.</p> <p>Degree of non-compliance significant.</p> <p>Limited recognition of the essential relevant components of effective health and safety management, but demonstrate commitment to take remedial action</p>	<p>Meets most of the relevant minimum legal requirements.</p> <p>Most success criteria are fully met.</p> <p>Degree of non-compliance minor and easily remedied.</p> <p>Management recognise essential relevant components of effective health and safety management, and commitment to improve standards.</p>	<p>Meets the relevant minimum legal requirements.</p> <p>All success criteria are fully met.</p> <p>Management competent and able to demonstrate adequate identification of the principal risks, implementation of the necessary control measures, confirmation that these are used effectively; and subject to review.</p>	<p>Exceeds the relevant minimal legal requirements.</p> <p>All success criteria are fully met.</p> <p>Management competent, enthusiastic, and proactive in devising and implementing effective safety management system to 'good practice' or above standard. Actively seek to further improve standards.</p>
<b>EMM INITIAL ENFORCEMENT EXPECTATION</b>					
Prosecution / Enforcement Notice.	Enforcement Notice / Letter.	Enforcement Notice / Letter.	Letter / Verbal warning.	None.	None.