Health and Safety Executive

Hydrocarbon leak reduction offshore – report on the findings of HSE's process integrity National Inspection Project (NIP) 2000-2004

SPC/Tech/OSD/28

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Purpose
Background
Further information

Purpose

This SPC contains links to the report on the findings of the process integrity National Inspection Project [PDF] 279kb.

Background

1 In April 2000, HSE initiated a campaign to reduce RIDDOR reportable hydrocarbon releases offshore to 50 % of the 1999-2000 baseline year. The target was to be achieved by April 2004.

Two projects were put in place:

the mandatory investigation of all RIDDOR reportable hydrocarbon releases from April 2000 to April 2001 and April 2003 – April 2004

a programme of planned process integrity inspections from April 2000 – April 2003 (extended to April 2004), referred to as the National Inspection Project (NIP)

The report associated with this SPC relates to the second National Inspection Project.

2 The NIP programme focussed on ten key process integrity related elements linked to the prevention of hydrocarbon releases. The report considers each element and summarises the broad findings and lessons arising from the NIP.

The ten key elements were:

1) Management of Process Integrity
2) Small bore tubing and piping systems
3) Information, instructions and training
4) Isolations and permits to work
5) Process plant protection systems
6) Change control
7) Maintenance and verification of process safety critical elements
8) Control of miscellaneous process hazards
9) FPSO (floating production, storage and offloading installations) specific hazards
10) Process plant construction and commissioning

Further information

The report can be found at: Hydrocarbon leak reduction offshore – report on the findings of HSE's process integrity National Inspection Project (NIP) 2000-2004 [PDF] 279kb.

Hazardous Installations Directorate
Offshore Division

SPC/TECH/OSD/28
(Fully Open)

Hydrocarbon leak reduction offshore

Report on the findings of HSE's process integrity National Inspection Project (NIP) 2000-2004

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Contents

1 Background

1.1 In April 2000, HSE commenced an initiative to promote hydrocarbon leak reduction in the offshore industry. The target was to see a 50% reduction in RIDDOR (**R**eportable **I**njuries, **D**iseases and **D**angerous **O**ccurrences **R**egulations) reportable hydrocarbon releases over the campaign period. The initiative used RIDDOR reported figures for major and significant hydrocarbon releases in the year 1999 – 2000 as the baseline against which project achievements would be measured. The 50% reduction was to be achieved by April 2004.

1.2 Two projects were put in place under the leak reduction initiative. Firstly, HSE undertook the mandatory investigation of all RIDDOR reportable hydrocarbon release events occurring during the year 1st April 2000 to 31st March 2001. This investigation programme was repeated from April 2003 to 31st March 2004. Secondly, the investigation project was coupled with a programme of planned process integrity inspections conducted on normally attended production installations between 1st April 2000 and 31st March 2003 (subsequently extended to 31st March 2004). This report relates to the planned process integrity inspection project conducted between 2000 and 2004, referred to hereafter as the National Inspection Project (NIP).

1.3 The NIP programme focussed on ten key process integrity related elements linked to the prevention of hydrocarbon releases. This report considers each element and summarises the broad findings and lessons arising from the NIP. Not all ten elements were necessarily applied or were applicable to all installations, e.g. FPSO Specific Systems. Some were applicable in principle but no relevant operations were available to inspect, e.g. Construction and Commissioning of Process Plant. Part 2 describes the ten elements used during the NIP.

1.4 The inspections conducted during the NIP were a sample assessment of the systems, procedures and practices applied to installations. The findings recorded in this report should not be regarded as a full and complete summary of issues or deficiencies that existed, or exist, in the management of process integrity across the offshore industry.

1.5 The tone of this report is concentrated towards highlighting areas of weakness that were found during the NIP and to this extent it is recognised that it presents a negative image of safety management offshore. This is not to say that sound process safety management is not being practiced in the offshore industry or was not found during the NIP. However, the focus of this report is on raising awareness of issues that warrant continued attention and lessons that can be taken forward to maintain and improve standards.

1.6 The approach adopted by HSE's inspectors in considering the types of good practice that should be, and often is, applied is contained in a set of NIP guidance notes to inspectors. These guidance notes were prepared initially to provide HSE inspectors with an informative project template for conducting inspections and to promote a consistent approach in the assessment of inspected practices. The content of these guidance notes is available on the **Offshore Oil & Gas** industry section of the **HSE Website** (**Health & Safety in the Offshore Industry – Information**) under the title of **Loss of Containment Manual – Reducing Offshore Hydrocarbon Releases** and is therefore not repeated in this report.

1.7 No comments are made in this report on the advisory or enforcement action taken by HSE against companies concerned as a result of findings arising from the NIP.

2 Process integrity inspection project key elements

Ten key elements affecting the safety management of process integrity offshore were used as the basis for the NIP. These elements are briefly described below:

2.1 Part 1 – Management of process integrity

This part reviewed the way in which process integrity is managed. The focus was on examination of the role of onshore management backed up by some validation offshore. The areas covered included an overview of management arrangements including policy statements, key accountabilities and responsibilities, training and competence, identification of basic causes in process incidents and the management of incident investigations, monitoring of process systems and procedures and the audit and review process.

2.2 Part 2 – Small bore tubing and piping systems

This part reviewed the way in which small bore tubing and piping systems are managed. It included the management of flexible hoses used in hydrocarbon duties. The areas were broken into four general categories covering management systems for small bore tubing, control of risks from vibration, small bore tubing systems in practice and the management of flexible hose assemblies.

2.3 Part 3 – Information, instructions and training

This part reviewed that way process integrity related documentation is maintained and key communications managed. It was conducted as a mix of onshore and offshore inspection. Areas covered included the review of documentation relating to design data and as-built status, safe operating limits and process plant protection settings, identification of plant and equipment, operating procedures, crew communications, plant monitoring and the monitoring and audit of document status.

2.4 Part 4 – Isolations and permits to work (PTW)

This part addressed isolation standards, locked valve controls, long term isolations for relief and vent systems, permit systems and associated monitoring arrangements. The inspections looked at procedures and their practical implementation, personnel awareness of isolation standards, responsibilities and monitoring.

2.5 Part 5 – Process plant protection systems

This part reviewed the way process excursions are prevented from violating the safe process operating envelope. It considered instrumented protection and alarm systems, including emergency shutdown systems (ESD), relief and blowdown systems. Areas covered included safety criticality, documentation, functional integrity and testing of instrumented protection and ESD systems, the control of inhibits and overrides, programmable systems and alarm system integrity. The philosophy, and operator awareness, of relief and blowdown systems design and operations, including risks of high to low pressure interfaces, were also reviewed.

2.6 Part 6 – Change control

Many major accident events on process facilities are attributable to change and failure of the controls in place to manage change. This part reviewed dutyholder's systems for managing changes to an installation and their evaluation before implementation. This includes the way change is initiated, communicated, analysed, implemented and reviewed.

2.7 Part 7 - Maintenance and verification of process safety critical elements

This part reviewed the way in which process safety critical elements are managed. The focus was on the identification and integrity assurance of safety critical elements (SCEs), and included review of management arrangements for control of corrosion, flanged joint and the review of ageing plant against current standards.

2.8 Part 8 – Control of miscellaneous process hazards

This part reviewed the way some miscellaneous process hazards are managed and on preventive controls. Not all hazards were relevant to every installation.

2.9 Part 9 – FPSO specific systems

This part reviewed process safety related factors specific to floating production, storage and offloading installations (FPSOs).

2.10 Part 10 – Process plant construction & commissioning

This part reviewed the way in which commissioning is managed, taking account of roles both onshore and offshore.

3 Key findings

This section outlines key findings on each of the ten elements of the NIP arising from the 4 year inspection programme. The findings are not a detailed list of every finding across individual installations, but are a distillation of issues and learning points that arise, supported by examples of deficiencies found during inspections. Some of the issues raised have been previously brought to the attention of the offshore industry and representative bodies in the form of interim findings as the NIP progressed. These are included here as part of the summation of issues at the conclusion of the NIP. OSD comment on the individual key finding is contained in the ‘greyed’ boxes associated with a particular finding.

All installation specific issues arising from the NIP were identified to the respective installation management at the time of the inspections with the intention that appropriate action could be taken to make improvements.

3.1 Part 1 – Management of process integrity

This element of the NIP focussed on examination of onshore arrangements to manage process safety. The aim was to establish a baseline against which performance offshore could be assessed in the remaining elements covered by the NIP. Issues raised under this topic area may often be tied into findings identified under the specific topic areas addressed under the other elements of the NIP programme (Parts 2 to 10).

3.1.1. Policy / record of arrangements

Most companies were able to demonstrate the existence of comprehensive safety management systems with the existence of well thought out and well documented systems and procedures. However, the systems that onshore management believed were operating on the installations did not always occur in practice. In many cases, when the application of these systems were reviewed offshore the situation was less satisfactory, and sometimes poor. There often appeared to be a mismatch between onshore management perception of performance against procedures and offshore reality.

Examples were found where the company had high level policy statements covering health & safety but none specifically related to process safety.

Interview with safety representatives on an installation indicated that they had never been consulted on the preparation of the safety case, the arrangements for the appointment of persons under Regulation 6(1) of PFEER or those under Regulation 7 of MHSWR. The frequency of safety committee meetings took place at the maximum interval of 3 months and this frequency did not vary with the level of platform activity or levels of risk engaged. All of the longer serving production staff thought that complaints raised by their safety representative had been justified. They also thought that the management was dictatorial, autocratic and did not listen to workforce concerns.

Involvement of the workforce and their representatives is an important component in developing and maintaining commitment to a strong safety culture and in ensuring strong links between management and the workforce in implementing safety policies. The level of commitment to this undertaking should reflect the depth of activity and level of risk. Management should be receptive to, and give due consideration to, well founded issues raised by the workforce.

3.1.2. Accountabilities / responsibilities / resources

Accountabilities and responsibilities were generally well defined, although on one installation it was found that each system had defined roles and responsibilities at higher levels, but not for Technician.

Clear job responsibilities should be assigned for process integrity functions and accountabilities reinforced through job descriptions.

The Operations Supervisor on an installation had recently taken on the role of both Operations Supervisor and Shift Supervisor due to reorganisation. Whilst some duties were absorbed by other personnel (e.g. OIM) the impression was formed that under conditions of abnormal operating and / or multiple complex tasks (e.g. during shutdown), the position of Operations Supervisor would be stretched, potentially affecting health & safety.

The company standard operating procedure for control of inhibits was missing on the installation. In its place there was an OIM instruction that had been criticised during an earlier inspection.

OIMs, as the senior management representatives on an installation, bear a particular responsibility to ensure, through good example, that company standards are applied.

3.1.3. Training / competence

On an installation, progress in successfully inputting data from the old to the new computerised maintenance management system had been slow. Extracting information from the new system was also proving slow. Maintenance technical personnel on the installation were unfamiliar with the new computerised system and were losing confidence in it even before they had become familiar with its use.

It is essential that sufficient investment is made by management to ensure timely and adequate data input, availability and system training on systems that have a global safety critical impact.

All new-start employees on an installation had adequate process experience for the job but several had no previous experience on an FPSO – a requirement that was cited in the job description. None of the new-start personnel interviewed had received any formal training or supervised and monitored on-the-job training and were picking the job up independently as they went along. This put pressure on the lead technicians, one of whom was himself a new starter. In one instance, both operators on the same shift were new-starts. Some of the operatives interviewed could not answer basic questions, (e.g. What is the current lifting colour code?).

Training for process personnel needs to include not only general training but also appropriate task specific training when required. Even experienced new start operators may require a refresher course of general process training to confirm and reinforce their basic understanding of systems relevant to the installation.

An installation's use of vendors to deliver specialised training on complex or novel equipment, or where there were health and safety implications from incorrect operation, was not extensive. On some systems, including high integrity protection systems (HIPs), no specific training had been given and personnel had acquired knowledge through their own efforts by 'standing by' over a period.

An inspection made during the early stages of the NIP found that no production staff on an installation, including supervision, had completed risk assessment training and there was a lack of familiarity of requirements. The outputs of risk assessments inspected were of an inadequate standard. Some production personnel showed gaps in their understanding of process safety issues. Incident investigation training, including appreciation of human factors and underlying causes, needed development. Many key personnel were 'not yet deemed competent' under the company management system and there was evidence of a lack of morale and uncertainty, etc. by staff. Whilst discussion with management indicated their intentions for training were sound, the implementation was slow.

3.1.4 Identification of basic underlying causes in process incidents

On an installation, visits were made to the sites of three hydrocarbon release incidents. Although the investigation procedure aimed to identify underlying causes, all three incident reports showed that this was not being adequately achieved. Identified **underlying** causes were actually **direct** causes, e.g. leaving a pump running on manual was a **direct** cause of a diesel spill; passing valves on the spool to an end cap was a **direct** cause of a gas release. Investigations had failed to identify other deficiencies, e.g.:

for the diesel spill,

- why the excess flow spilled over the vent instead of to a bulk tank via an overflow;

for the gas release,

- why the spool piece was not on the P&ID,
- why the valves were passing,
- why the stainless steel spool was connected to mild steel pipework
- without an insulating flange (an identified requirement),
- why no sealant was used on the end cap,
- whether the addition of the spool was an authorised modification.

The identification of underlying causes of failure requires close attention and may require a level of specialised technical support or knowledge that may not exist on the installation. The superficial causes of an event may appear obvious but can lead to conclusions being too easily reached and valuable lessons missed. Those involved in analysing the causes of incidents need to be fully trained in the process of tracing the pathway to root causes and in recognising subsidiary failures.

Inspection of an installation provided no clear evidence of a system for identifying basic or underlying causes of incidents. It appeared that each incident was treated individually and root cause analysis could take a number of possible paths. Action tracking was not evident and did not link in to audit.

It is important that a consistent and systematic approach is adopted for finding root causes of incidents. The logging, assignment and tracking of actions arising from the results of investigation should be systematically applied.

3.1.5. Monitoring of process systems and procedures and the audit and review of process plant and management systems

Early in the NIP, examples were found where offshore personnel seemed unaware that certain procedures existed. Onshore management were often unaware of this situation, suggesting a weakness in the implementation of arrangements for audit review and monitoring. Following these early findings, there was some improvement noted, but still scope for more. In general, it is important that the monitoring, audit and review processes are consistently and effectively implemented. This is particularly important because of the physical separation between offshore installations and the onshore management which places additional burdens of communication.

As an example of the above, during an onshore inspection, inspectors were advised that major procedures such as Permit to Work and Isolation Procedures had been fully computerised to allow instant access offshore of updated documents – an impressive system. However, when followed up offshore for a recently changed procedure, it was found that operators were not using the current version. The reason given was that operators offshore found accessing procedures on the computerised system too difficult and had ceased to use the system. They carried on with what they had. In this particular instance, it was found that training had recently been given on this specific topic using procedures that were two issues out of date. This showed that management systems needed to be more effectively monitored.

Where necessary, training needs to be sufficient to ensure new methods are applied (in this case the use of the computerised system). This is particularly important where new document handling systems are changed, affecting many or all areas of the management system. This is effectively a common cause failure of a key management system. It is also a reminder that management of change does not finish with implementation of the basic change. It also includes follow-up monitoring.

All ESD inhibits on an installation were satisfactorily explained but some of those for the F&G system were found to be more than a year old. It was alleged that there had been an inspection which audited all inhibits but the associated audit report document did not agree with records in the inhibit log for the F&G system (a safety critical system). Safety critical inhibits should be closely monitored and controlled.

Safety critical component availability should not be reduced unless absolutely necessary, and only then with the safeguard of adequate risk assessment provision. When inhibits are placed, a return to full serviceability should be expedited without delay. Audit mechanisms should ensure that safety critical inhibits and their standing durations are not overlooked.

Audit and review was carried out across an asset. However some comment was received from offshore personnel to the effect that there was too much auditing, with quantity seeming more apparent than quality.

It is important that audit programmes are suitably targeted and sufficiently searching to effectively test the application of the management systems and for the audit results to have lasting influence.

A programme for monitoring of an installation's systems and procedures was seen to be in place offshore. The quality of these monitoring arrangements was not inspected in detail. However, a number of deficiencies were found with control of overrides that should have been detected through effective monitoring.

Poor monitoring contributes to the risk of major accidents. It is not just the existence of systems and procedures that prevent accidents, but also the effective implementation of those systems and procedures. Monitoring is an essential step in preventing accidents through encouragement and feedback of positive achievement - but only if it is sufficient, targeted and adequately penetrating.

Active monitoring of an installation was considered to be an exclusive offshore activity. The Production Superintendent was not systematically involved in active monitoring and a great reliance was placed on the Daily Report and Process Log. Apart from first line audit checks conducted on the installation, there were no recent examples of process system audits. Audit work scopes appeared not to be linked to performance in any specific areas.

Audit programmes should be influenced by performance indicators such as near misses, incidents, inspections and the results of monitoring initiatives offshore etc. Audit teams should display independence and impartiality.

Whilst there appeared to be good work on training and competency elements of process integrity on an installation, there was no evidence of senior management audit of this key process integrity element of the safety management system (SMS).

Inspection of an installation identified many failures to manage safety critical functions. Some examples included:

- many failures to manage valve lock controls;
- retention of the inhibit 'Enable' key in the 'Enable' position;
- ESD cabinet doors that should have been locked closed were found open allowing unauthorised access;
- purge air fans contributing to the statutory 12 air changes per hour were turned off despite a red notice warning of the need to not switch them off as they were part of the safety system.

The platform was visited on a number of occasions to follow up on findings. Inspectors were surprised to find that many reported issues remained unresolved. The extent of repeated deficiencies appeared to suggest a lack of senior management interaction and the lack of audit and monitoring was seen as a contributor to the failure to make timely and effective improvements.

3.2 Part 2 – Small bore tubing and piping systems

3.2.1. Management systems and practice for small bore tubing

During HSE's inspection of small bore tubing, it was anticipated that this would concentrate on compliance with the UKOOA/IP 'Guidelines for the Management, Design, Installation and Maintenance of Small Bore Tubing Systems', published in June 2000 by the Institute of Petroleum. However it became apparent during the early stages of the NIP that a number of companies were unaware of the existence of this guidance and, more importantly, were working to procedures that fell short of recommended practice in areas such as the uncontrolled usage of different types of fitting and in the lack of formal policies, clear competency standards, etc.. Since then, efforts were made to promote the UKOOA/IP guidance and awareness. Practices noted in later inspections were seen to have improved. Even so, adverse findings concerning small bore tubing systems were reported for over a quarter of all installations covered by the project or around 40% of the installations where this topic was specifically addressed. An interesting observation of good practice later found on one installation was the issue of small tubing components being retained under lock and key and only being issued to technicians who produced a training certificate. A sample of issues relating to this topic include:

Onshore, the company were aware of the UKOOA/IP guidelines for small bore tubing, but at the time of the inspection did not have a committed management policy. There were no specific maintenance or operational instructions for small bore fittings, although it was claimed there was a general awareness by the crew of the potential and consequences of failure. A training matrix included offshore personnel who had been trained in a brand of small bore fitting, but this was later found to be incomplete. When followed up offshore, it appeared that competency was not being well controlled or monitored. Several personnel had not done manufacturer specific training and there was no evidence of an evaluation of the need for refresher training. A physical inspection of a sample of 30 – 40 fittings found a number that were incorrectly made-off and there were some minor leaks. Hydraulic lines were examined and many, especially in the wellhead control package, were found to be leaking.

It is important that integrity of small bore tubing is properly addressed over the life of the plant within the management policy and system. This should include identification of small bore tubing systems within the engineering design, construction, maintenance and operations standards and procedures, with emphasis placed on competency. Appropriate manufacturer specific training should be provided to those required to assemble small bore tubing fittings.

On reinstatement of small bore tubing, full leak checks were said to occur on the process plant. However, there was no management requirement to leak check small bore tubing impulse lines after intervention. These should be leak tested.

Inspection of another installation showed that whilst post assembly leak testing of small bore fittings was recognised as good practice on the installation, it was not called for in any documentation. A sample of about 50 tested joints found multiple leaks on impulse piping.

On an installation the OIM was not aware of the IP/UKOOA guidelines covering small bore tubing systems. Maintenance and operational procedures did not specifically cover small bore tubing.

An installation could not provide evidence of any central control for issue of small bore tubing fittings from storage.

A company had conducted audits of small bore tubing arrangements, covering management and technical aspects. Several deficiencies with the same issues were identified in each audit. One of the findings was that approximately 5% of a sample of 850 – 1000 fittings were insufficiently tight.

At an onshore meeting, it was stated that there was a company procedure for management of small bore tubing systems. However, no evidence was seen of the procedure offshore and the OIM confirmed at the end of the inspection that it had not been traced.

The IP/UKOOA guidelines for small bore tubing were not readily available on the installation. The document was available on the company IT database but those spoken to, including the OIM, were not aware of its existence. It was surprising that 3 years after publication, this key guidance document was still not known by key personnel, despite its presence on the company database.

This reinforces the finding under Part 1 of the NIP (Management of Process Integrity) that onshore management perception of what happens is not always implemented offshore in practice and demonstrates the need for adequate monitoring of systems by management.

An installation did not check the competence of vendor staff in making up small bore connections but believed that this was all dealt with as part of the onshore vendor selection process. On another installation, when tubing systems were installed by vendors, there was a reliance on the vendor providing competent staff, with little checking/verification.

A caution is to be noted here on the presumption offshore regarding activities being conducted onshore.

3.2.2. Control of risks from vibration

Many installations had implemented, or were implementing, studies into identifying sources of vibration. The NIP did not specifically examine the content of these studies in detail. However there were some examples found where further work was needed.

A vibration study had been done on an installation but action to implement findings was slow. The study report indicated over 320 concerns, of which 86 were said to require modification 'as soon as possible'. The actual modification required for each of these anomalies was specified in the study report, but at the time of HSE's NIP inspection nearly a year later, none had been implemented.

No specific vibration survey had been undertaken on process pipework despite the fact that certain pipework had been identified as problematic.

3.2.3. Control of small bore flexible hoses for hydrocarbon dut

This area addressed the use of flexible hoses throughout their lifecycle, including field installation practices, integrity, competency and training. On the matter of small bore flexible hoses, it was evident during the early stages that there were no clear comprehensive industry or company standards or guidelines that dealt with hose properties and use, installation practices, testing, risk assessment, etc. Since then the UK Offshore Operators Association (UKOOA) Hydrocarbon Releases Working Group, working in conjunction with HSE and with vendor representation, chaired a committee to produce a set of Flexible Hose Management Guidelines under the UKOOA/HSE/IP banner. These guidelines were published in January 2003. The lack of clear guidance on hose management produced many examples arising from inspections that demonstrated the existence of incomplete or inadequate procedures. A sample of findings on individual installations include:

Lack of complete records for management of flexible hoses. One hydraulic supply hose to an upper master valve was found badly damaged requiring immediate replacement.

Whilst a flexible hose inspection system was in place, it only applied to portable hoses and not to permanently installed hoses.

A risk based inspection system should be applied covering all flexible hoses that form part of a safety critical system.

There were many examples of flexible braided stainless steel hoses which were not subject to regular inspection nor were they identified on any register.

An installation had no procedure or standard means of distinguishing between hoses used for different duties (common connections) and no colour coding system. Although the ‘standard’ colour was said to be black, different colours were being used.

Certificates for armoured high pressure (HP) hoses were said to be kept by the independent competent person (ICP). An examination of hoses on site found a HP (>2000 psi) hose in the well bay with a damaged outer sheath and a HP nitrogen hose had visible bulges. Another nitrogen hose had a date stamp of 1995. Whilst appearing to be in sound condition, there was no evidence of inspection since that date.

An OIM was unsure of the inspection regime for flexible hoses relating to his installation.

Hose management on an installation included a 6-monthly inspection by a hose manufacturer. A report was completed identifying hose location, tag number, type and defects found on hoses requiring replacement. The defect list was then passed to operations and maintenance departments and once work had been completed the Platform Mechanical Inspector was informed. Inspection of past reports showed there was no documentary evidence verifying that hose replacement had occurred (no audit trail).

3.3. Part 3 - Information, instructions and training

3.3.1. Design status, as-built status and the monitoring of documentation

The Safety Management System (SMS) should ensure that information for process equipment and its use in process operations is provided to an appropriate status and that documentation changes are suitably managed. The proper management and control of hazardous operations interfaces heavily with the use of appropriately controlled documentation that reflects the as-built status of the plant. Examples of issues arising from the NIP affecting documentation control include:

Examples across several installations of failure to maintain critical documents (e.g. Piping and Instrumentation Diagrams (P&IDs), operating manuals, etc.) up-to-date, or inappropriate delay in updating documentation to reflect modifications. In one case, Approved for Design (AFD) rather than As-Built P&IDs and Cause and Effect diagrams, and pre-modification operating procedures were in use following completion of a major modification project.

Inspection of an installation found incomplete updating of key controlled documents (e.g. P&IDs, Cause & Effect (C&E) diagrams, operating procedures). On another installation. P&IDs and C&E diagrams were reviewed and appeared up to date, but the associated P&ID and C&E manuals did not appear to be controlled documents. C&E diagrams were stamped to say they were CAD produced and must not be manually updated. However the version in the control room had been manually updated several times. Document control arrangements needed improvement.

Maintenance and document control of key documentation to current as-built status is an important element in the management of process safety across all areas of plant operation, maintenance and management of change.

Use of ‘Controlled Copy’ documents were found that had no unique copy reference number to allow tracking of revisions and assurance of current status.

Failure to identify and manage controlled copies is an abuse of the controlled document management procedures and can lead to out-of-date information being used.

Some procedures were found that were not signed off as controlled documents. All documents were kept on a database from which copies could be printed off as required. There was no system for ensuring and controlling the destruction of old paper copies that had been printed in this way.

Modification changes were marked on a set of P&IDs and records sent onshore for updating the CAD (Computer Aided Design) drawings. However a spare set of old drawings were also kept in the control room as these were marked with maintenance area codes used during work allocation. There appeared to be no system to ensure that the set used for maintenance area coding purposes, which was potentially out of date, could not be used for any purpose where accurate as-built drawings were required.

Minor corrections to P&IDs arising during routine operations on an installation were typically marked up on a master set of drawings held on the installation. Following a recent shutdown, P&IDs consisted of a pre-shutdown Master plus one or more attached P&IDs showing amendments from the work packs.

Multiple amended drawings can cause confusion and should be updated as soon as possible.

Valve registers were found that were not accurately linked to requirements shown on P&IDs. This conflict of requirements can result in safety critical valves being left in the wrong position (open or closed) with the risk of loss of containment.

Although trips were shown on P&IDs and appeared up-to-date, an instrument index was out of date and there was no trip register.

Although there was a system for distribution of controlled drawings, there was no document revision list available offshore on the installation.

3.3.2. Safe operating limits and process plant protection settings

The identification of safe operating limits for parameters such as pressure, temperature, level, flow and a record of protection settings are an important component in the safe operation of hazardous plant. Issues found included:

Several examples were found of incomplete population of databases with critical information such as trip and alarm settings.

A spreadsheet matrix of alarm and trip settings was in use by technicians when undertaking plant checks. The document was not a controlled document and did not exist on the central computerised document system or in procedures.

On an installation, whilst normal operating limits were identified in the operating procedures, maximum (i.e. safe) operating limits were not included.

Safe operating limits were shown on P&IDs and there was a register of trip and alarm settings. This was a computer printout with manual amendments. It was not a controlled copy, but was maintained by the technical custodian for instruments and used in the control room. It was found subsequently that protection settings were also held on a database.

There needs to be an unambiguous robust controlled system in place for documents containing key operational safety related data.

A company had been moving to PC based documentation for all controlled documents. Information was held in 3 different databases. Some updating was required and the databases needed to be populated in a number of areas. There was no separate register of trip and alarm settings, but the relevant data should have been on the database. Several omissions of alarm settings on the database were found.

The transition period between old and new company systems needs to be managed to ensure that key operating data is kept up to date, is complete and remains readily available.

3.3.3. Identification of plant and equipment

Accurate identification of lines, valves and equipment is important in promoting safe isolations. There have been several examples of incidents where the wrong item of equipment has been operated or maintained. In harsh environments it is particularly important that tags and their attachments have sufficient integrity throughout their expected life. Example findings include:

Plant and equipment on an installation was identified by tags or fixed identification plates. Some tags were found to have been lost and not replaced. Control valve tagging was poor with tags either missing or marked with felt tip pen.

A high proportion of valves on an installation had no identification tags. There were also some deficiencies found with identification of instruments and vessels.

Few manual isolation valves on an installation were tagged, or had poor tagging clarity or accuracy, with no register linked to P&IDs.

3.3.4. Operating procedures

Operating procedures should be of sufficient scope, be user friendly and, importantly, be kept up to date. When conducting theme audits in the past, HSE has noted problems with operating procedures found to be inadequate or out of date. The following example findings indicate that attention to currency and status of these key documents should be maintained.

Standard operating procedures and P&IDs were found that were not being kept up to date despite the existence of a requirement in procedures for a minimum review period of 12 months.

Some operating procedures/training manuals were not current and needed review in line with current practice.

Operating procedures were found on an installation that were still pre-modification status and had not been revised in a timely manner to reflect the current as-built arrangement following a major plant modification project.

3.3.5. Training / competence

Safety related training specific to process personnel should be supplied and recorded. Training records should be kept up to date.

A training matrix showing the status of personnel training was out of date and included personnel who no longer worked for the company.

3.4 Part 4 – Isolations and permits to work

Part 4 of the NIP dealing with isolation and PTW controls produced the largest quantity of findings in any one topic group, with findings being reported on around one third of all installations covered by the project. This is an important observation as the management of safe isolation and PTW lies at the core of preventing hazardous releases and potential major accidents.

3.4.1. Isolation standards and procedures

Companies generally had procedures for the management of isolations but these could be compromised if not understood or followed in the field. Many installations have developed procedures for determining necessary levels of isolation based on, or similar to, the Oil Industries Advisory Committee (OIAC) guidance document C50 'The Safe Isolation of Plant and Equipment', published as a Health and Safety Commission (HSC) document in March 1997. However there were many cases found where systems for determining and applying isolations were deficient in approach or application. Example issues affecting isolation standards and procedures arising from the NIP included:

Use of more than one procedure on the installation to determine isolation standards. This is a potential means for confusion if the wrong procedure is used or if operators inadvertently apply mixed requirements. There should a single consistent procedure applied to the determination of required isolation standards.

Appropriate training in the understanding and application of assessment methodology and processes to establish the required isolation, and the monitoring of continued performance is essential.

Company isolation procedures were sometimes found to be less rigorous than the OIAC C50 guidance recommendations, or company guidance was otherwise limited in its scope. An example was found of an isolations procedure that appeared to allow vessel entry with less than positive isolation (i.e. removable spool, spade, or equivalent) with OIM agreement.

Intrusive entry with less than positive isolation is not considered to be consistent with recognised good practice.

Failure to follow procedures in isolation for intervention, including incomplete labeling of valves, some locks not installed and failure to test double block and bleed (DBB) arrangements per company standards.

Deficient safe working practices/procedures for checking that all routes for flow into equipment are visually checked for disconnection/isolation.

Examples of deficiencies in arrangements for proving / monitoring integrity of isolations (e.g. lack of vent or drain to check for trapped pressure behind isolation)

Use of blanket signatures on group isolation certificates rather than signing each isolation individually.

Errors have occurred where grouping brackets were not distinct in defining the affected isolations. Errors can also occur where isolations are accidentally included or left out of the ‘group’. This blanket signature approach should therefore be regarded as poor practice. Individual signatures for each isolation requires a deliberate act to sign off and is more reliable.

Instances were found of ambiguous identification systems for spades, slip rings (spacers) and restriction orifices, leading to the potential for mistakes in identification. For example, the identification for spades and spacers both appearing the same when installed, with both having one hole in the tail instead of following the recommendation of one hole for a spade and two holes for a spacer, as suggested in the OIAC C50 isolations guidance document. This allowed the potential for confusion between a positive isolation and an open line.

Cases were found where the mechanical isolations certificate recorded where valves and spades were fitted and reinstated, but no identification on the certificate was made identifying that the correct status (i.e. open/closed) was being maintained.

Operational integrity can be severely compromised if component status is not also controlled (particularly on reinstatement).

- The isolation system was based on OIAC C50 isolations guidance for safe isolation of plant and equipment. However a single sample isolation scheme inspected revealed that out of seven valves in the scheme, five had no label, one had no disc, one had insecure chaining and another had its handwheel detached due to corrosion. This suggested that the monitoring system for these isolations was deficient.

- Examples were found of failure to implement the outcome of a Hazard Factor Analysis (see OIAC C50 guidance). A Hazard Factor Analysis may be used to determine the required level of isolation based on the consequence of a failure of the isolation, taking into account the effect, nature and duration of a release.

- Examples of anomalies in the application of the isolation assessment method (e.g. Hazard Factor calculation for selection of isolation system required) were found. Different operatives showed varying understanding of the application of the assessment methodology leading to different outcomes in the assessed required level of isolation. This may have training implications in the application of assessment methodologies as well as for the selection and installation of the appropriate methods of isolation. In one case, the guidance in procedures on selection of isolation standards was limited and appeared to rely heavily on the discretion of the Operational Supervisor. OIAC C50 guidance for determining an appropriate standard of isolation using Hazard Factors was not followed.

[It is noted that the OIAC C50 guidance on isolations is undergoing a review at the time of this report. Some of the issues of interpretation and application of criteria affecting isolation selection may be more clearly addressed in future guidance publication.]

3.4.2. Locked valve controls

Locked open or closed valves are widely used in safety critical applications to guard against mal-operation of isolation valves that have a potential to lead or contribute to major accidents if not correctly positioned. Generally, the importance and purpose of lockable valves is understood within the industry. However, many examples of failure to manage these safety critical components occur. Some thematic issues found during the NIP include:

- Register of Locked Open (LO) and Locked Closed (LC) valves not updated or properly signed off on a regular basis or a lack of suitable registers. Examples of valves were found that did not reflect the P&ID requirements for locked status.

It is recommended that P&IDs be suitably marked up to clarify requirements. Regular supervisory checks should be made on isolations and the status of LO/LC valves.

- Several examples were found of failure to install locks where and as specified, or of valves being locked in the wrong position. Examples found during the NIP included:

  - An isolation valve lock missing following maintenance work on an inspected system despite existence of a 'locked valve' and 'locked spade' register. This is an important area as poor management and incorrect positioning of locked valves has contributed directly to some major incidents involving loss of containment.

  - A Double Block & Bleed (DBB) arrangement was seen on a well where valves were not securely isolated and having no locking device – one of the valves was at 45^{O}, being neither positively open nor closed.

  - Examples of valves labelled LO/LC which were not locked at all.

- Many examples were found on an installation of safety critical valves that had not been included in the LO/LC valve system of control.

- Inadequately robust methods used to 'lock' valves in the required position, e.g. plastic ties with labels that can be easily defeated, loose fitting chains or wires allowing valve movement, etc.

- Dedicated locks are a preferred method of control, depending of consequence of failure to lock as specified. Examples of poor practice found include:

  - A valve in the minimum flow recycle line from a water jetting pump had a loop of wire around the handle and a 'DO NOT OPERATE' label. The wire loop was not secured to the valve or pipework sufficient to prevent operation.

  - Several examples of carseals on valves that were missing or badly corroded, some dropping off when touched. Others seals were found that were slack, allowing valves to be moved from their secured operating position. The failure extends to a demonstration of poor monitoring and auditing.

  - A carseal had been defeated on a well swab valve. The seal was part of a controlled closed isolation. The seal had been broken and the valve temporarily moved to open despite a current isolation certificate being in force. The reason for this departure was failure to obtain a 'sanction to test' which would have enabled a legitimate opening of the valve. The procedural system was bypassed in favour of a quicker option and as a result the valve had not been restored to its Lock Closed status.

- Interlocks being defeated due to lack of control on interlock / master keys. One example found concerned the pressure safety valve (PSV) isolation valves on a Test Separator (2x100% PSVs) that were required to be held in the correct position by interlocks. However both keys were left in place in one up stream valve allowing potential operation and compromise of the duty PSV. The second key should have been returned to the central control room (CCR).

3.4.3. Long term isolations (LTI)

On a number of installations inspected under part 4 of the NIP, ‘Process Isolations and PTW’, the management of LTIs raised several issues. Themes and specific example issues arising from the management of long term isolations include:

- No clear separate system for logging long term isolations on some installations, i.e. all short and long term isolations being subject to the same checks.

- Failure to keep a register of where valves were used in LTIs with reliance being placed upon change work packs to monitor such isolations. This makes it difficult to check LTIs due to poor records.

- LTI tag labels were found in some instances to contain obliterated information due to environmental exposure, or had become detached, possibly due to high winds.

Temporary tagging arrangements (labels and label ties) need to be of sufficient durability to remain legible and securely attached throughout the life of the isolation.

- There were examples of no label differentiation between those for LTIs and any other (short term) isolations. This should be considered to facilitate routine observation of the plant status and auditing of LTIs etc.

- The integrity of long term isolations required improvement. Examples of variable monitoring standards were found and a case of internal audit recommendations not being implemented.

- Examples were found of installations not applying any regular formal auditing or review of long term isolations to confirm the ongoing requirement for them to remain in place, or to expedite the issues affecting their removal.

- Long term isolations were reviewed by the company on its installation, but only on the isolation standard applied. The review should also have covered the effects of extended isolation on affected systems. Reviews may need multi-disciplinary input and may trigger change control.

- During examination of the long term isolations car seal register, it was noted that a number of entries did not have car seal numbers assigned. This was a failure of the use of an important control procedure and of the monitoring of procedures.

3.4.4. Isolations for relief and vent systems

Relief and vent systems are required to be available at all times to protect operating plant and ensure an open path to atmosphere or flare, as appropriate. The maintenance isolation valves that are associated with these systems need to be subjected to suitable locked, preferably interlocked, systems of control that ensure the integrity and availability of these safety critical systems. Relief valves are often located at high to low pressure interfaces between high upstream pressure systems and low pressure relief and vent disposal systems, creating particular reliance on the correct and secure positioning of isolation valves.

- An inspection found that both inlet and outlet isolation valves on standby relief valves were locked closed. The downstream valve should be locked open to guard against potential leakage from the upstream isolation valve and relief valve leading to overpressure of the lower rated downstream isolation valve and piping.

- An instance was found where the mechanical interlocking devices were removed from the upstream and downstream isolation valves associated with a safety relief valve. The interlocks had been replaced by manual handles with locking wires – an inferior securing system. Isolation valve tags were also found to be incorrect (wrong way round).

- An installation was found to have applied an inconsistent isolation philosophy for relief valves.

- The low pressure and high pressure flare drums on an installation were protected against overfill of liquids by provision of high level (LSH) and high-high level (LSHH) switches and alarms. The primary isolation valves for these switches were not locked open (LO). Inadvertent closure of these primary isolations would have disabled the warning and protection arrangements. The isolations associated with the LSHH should have been LO, as a minimum, for this protection system of last resort on these safety critical disposal systems.

3.4.5. Permit to work (PTW) systems & monitoring of PTW and isolation procedures

PTW procedures are a fundamental control measure to manage the safety of intervention on hazardous plant. Procedures should define the tasks to be undertaken, record the output of appropriate risk assessment, define the precautions to be taken and any other relevant actions. The application of the PTW and isolation system should be effectively monitored. There were a number of failings of this safety critical process observed during the course of the NIP. Examples are outlined below:

- Records on an installation showed that work permits were being monitored and audited by a range of different personnel in accordance with a schedule for such inspections (30 permits a month). Despite this, nobody appeared to have uncovered multiple fundamental failings that were noted during HSE’s inspection for this NIP topic. In brief, issues were found that related to:

    - use of different and out of date procedures
    - poor tagging and failure to differentiate between short and long term isolations
    - insecure locking of valves

- inadequate risk assessment
- current procedures from the computer system were difficult to access and personnel appeared unfamiliar with using the system (poor training).
- a particular concern to HSE inspectors was the fact that these findings were found in a later follow-up inspection to an earlier visit during which some of these issues had already been raised.

It is essential that monitoring of the application of core operating procedures is effective and not simply regarded as a hoop to jump through. Failure of operators to use and implement current procedures and failure of management to effectively monitor these processes points to a fundamental safety culture deficiency across all or many sections of an organization.

- An incorrect PTW procedure document was in use on a platform and there was no master or controlled copy of the reference document in the control room.

- The installation PTW procedures required a risk assessment to be done but this did not always happen. Experience was sometimes used to replace formal risk assessment.

- This was unacceptable and contradicted procedures. Further issues arise over the application of adequate audit procedures.

- The installation had no restriction on the number of hot work permits allowed at any one time and no visual system in the control room that indicated where hot permits applied. This would assist in the event of a major incident.

- P&IDs were used to identify isolation blinds, but the relevant isolation valves were not marked. Copies of marked up P&IDs were not available in the control room.

Failure to identify isolations in the field could lead to errors in de-isolation. Control room operators should have current plant status information available.

- It was noted during inspection that single valve isolations could be applied on the installation by completing a form. However there was no formal procedure or guidelines indicating criteria where single valve isolations could be applied as an acceptable standard of isolation, nor on who could give authorisation.

Guidance should be available to define the level integrity of isolations.

3.5 Part 5 – Process plant protection systems

3.5.1. Instrumented protection and ESD systems

UKOOA 'Guidelines for instrument-based protective functions' provide a basis for the assessment of safety criticality of these functions as safety critical elements (SCEs). These safety critical functions should be documented and high integrity protective (HIPs) functions should have systems in place to ensure that the process safety intent is achieved through design and testing. Examples of findings arising from inspections include:

- Examples where no current and recorded evidence was found that safety criticality of instrumented protective functions / ESD functions had been established and assessed using the UKOOA 'Guidelines for instrument-based protective functions' (or similar).

- On one installation, several deficiencies were found. The installation had been moving away from paper copies of trip registers, with information being transferred to a database. In principle this was good except that a number of gaps were found. Several trip settings could not be found and a search for a randomly selected instrument data sheet found it was missing. Cause and effects charts were on the database, but a version on the database was less recent than one found on the installation in hard copy format.

- An installation could provide no evidence that the requirement for application of overrides had been adequately considered as part of the design, e.g. no SIL assessment or guidance on circumstances in which particular overrides might be put in place. In practice, any assessment carried out before overrides were put in place appeared informal.

- Many safety critical instrumentation systems on an installation depended upon an intrinsically safe (IS) earthing system for electrical integrity in hazardous atmospheres. There was no evidence to show that the performance or integrity of these IS earths was ever tested or inspected. If compromised, a potential common mode covert failure affecting multiple circuits could have occurred.

- Whilst the installation had procedures to test ESD inputs on a regular basis, there was no system for the complete testing of ESD loops from input to output executive action. Reliance was placed on the ICP to check a sample of loops from end to end. Although the choice of loops was agreed between the ICP and the operating company, there was no evidence that each ESD loop was checked from input to output on a regular basis.

3.5.2. Control of inhibits / overrides

Inhibits and overrides may be required to allow some plant to be started or maintained. The scope, risk assessment control and monitoring of overrides should be carefully controlled. A repeated issue was the lack of formal arrangements to review the need for, and reassess the impact of, long term inhibits and overrides. Some example findings from the NIP include:

- Inspections found examples of installations where risk assessments were not being carried out when inhibits were placed.

Placement of inhibits are a change to normal operation and should be subject to appropriate risk assessment.

- For example, on an installation, the procedure for control of overrides was deficient in that it had no specific requirement to ensure a risk assessment was carried out before application of overrides. No risk assessments were evident for any of the overrides applied and no additional precautions had been specified. Some overrides in the log had not been authorised by the OIM. When overrides had been taken off, the reinstatement had not always been logged. Operators advised that overrides were often applied for some ‘routine’ operations with no entry being made in the override log. The most common example was for override of a low pressure trip.

- Overrides on live equipment were in place and should have been subject to a Temporary Modifications Procedure. However the procedure had not been followed.

- Three overrides were in place. Assessment records were adequate for the initial application, but the overrides had been in place for several months with no indication of review actions having been taken to allow the overrides to be removed.

- There were 11 inhibits that were in place on an installation, of which 7 were of long term nature. There was no evidence to suggest that these had been formally risk assessed to justify their continuation, nor any clear plan to remove their requirement. Some inhibits had been in place for 3 years, apparently for operational reasons.

- An inhibits register showed 32 inhibits were in place of which 28 were long term. Justification for these inhibits was supported solely by existence of original risk assessments. However there was no evidence of any subsequent reviews. Regular reviews are necessary to see if numbers of long term inhibits can be reduced on a prioritised basis.

- Examination of some inhibits on an installation showed that inhibits were logged but there were no accompanying risk assessments. Some inhibits had been in place for over 3 years.

- Whilst no problems were noted with the recording of short term inhibits on an installation, monitoring was deficient in detecting issues dealing with long term inhibits. Monitoring had been allocated to the Operations Team Leader (OTL). According to the schedule, monitoring should have been done in January and April. However the OTL had not carried out this formal monitoring, claiming that since he reviewed inhibits every day there was no need for additional monitoring.

This highlights issues whereby a person is assigned to monitor things for which he already has responsibility. The issue of adequate independence in the monitoring process when allocating monitoring responsibilities needs consideration.

- There were five inhibits on the ESD and two on the Fire & Gas (F&G) system recorded in a log. There were also some inhibits applied that were not recorded on the log, but were under the short term control of the control room operator. All inhibits had been subject to a risk assessment, but these had been done by the Lead Technician who had not been given risk assessment training. The risk assessments inspected were considered inadequate in terms of their content and the lack of additional control measures considered. In respect of the two short term F&G inhibits, a panel mounted key switch had been operated in addition to the software amendments. The key switch inhibited an entire zone of both fire and gas detectors. It had arbitrarily been applied as a 'belt and braces' measure.

- An installation had a system for controlling inhibits and overrides in place. However, in unattended control rooms the override key switches were kept in the shutdown panels, including the master override key.

Security of overrides in unattended control rooms should be maintained.

- All ENABLE key switches for ESD were kept permanently in the enable position allowing remote placement of overrides for maintenance by others. This provided the potential for the CRO not to be informed of an override unless told verbally and an entry made in the override log.

- Some ESD cabinet doors which should have been locked closed were found open allowing unrestricted access to ESD maintenance override keys. All production and maintenance technicians carried keys to these doors.

- Keys were provided to allow overrides to be applied to ESD functions. Some were found in the control panel and some were in a key box near the permit desk. A register was kept of overrides applied, but there was no effective control over the keys which were all identical. The number and availability of keys should be restricted.

- An installation's system for recording overrides needed attention. There was an OIM's local instruction on the front of the inhibit register but multiple deficiencies were found that included:

  - No system of approvals for the application of inhibits
  - No formal risk assessment – no records
  - No control of override keys
  - No system of security on the application of software generated inhibits.

The use of an OIM local instruction is not an acceptable substitute for a formally authorised set of procedures designed to ensure that all essential elements of a sound safety management system related to key safety critical functions are applied.

- Fire and gas (F&G) overrides on an installation appeared to be logged in a dedicated register for each application, but the process override log showed that process overrides were infrequently logged. There was a page of long term overrides, including eight that were designated as permanent. There was no evidence that these had been reviewed to see if they could be designed out.

3.5.3. Control of programmable systems

Two DCS systems were in place - one for general process and one dedicated to a sub-sea manifold. Computer clocks were not synchronised preventing accurate monitoring.

3.5.4. Alarm systems integrity

Process alarms assist operator intervention to manage plant operating variations and can reduce the demand upon formal protective systems. Alarms and their displays need to be of adequate integrity if this additional layer of protection is to be effective. The impact of multiple alarm displays on human performance needs to be taken into account. Example issues arising during the NIP include:

- On an installation there were many standing alarms on control and common alarm panels. Also, there was no evident means of differentiating the important alarms from less important ones.

- It was acknowledged by the Control Room Technician and the Production Supervisor that alarm floods occurred during process upsets. It was often difficult to ascertain the alarms of most interest due to the number and rate of alarms being shown. On commonly used process screens, only the last alarm raised was displayed, which was often not useful to operators.

Alarms should be reviewed with the aim of decreasing the risk of alarm overload during the initial stages of a process upset and ensuring that important alarms are readily available to operators.

- An installation had in excess of 4000 alarms divided into three importance categories of action, fault, and transmitter drift. There was a high potential for alarm overload and a significant number of standing and spurious alarms. Many of the drift alarms were not deemed valuable by operators and were often ignored. Alarms were not displayed in a logical fashion with process alarms mixed with F&G alarms. There was no first up alarm, though the event printer could assist with diagnosis.

Companies should seek to ensure that numbers of alarms that serve no valued purpose are reduced to ease problems of alarm overload. Alarms should preferably be grouped to distinguish between functions.

- The grouping of panel alarms on an installation needed improving to minimise risk of human error. Two operators who were fairly new to panel operation found the alarm system confusing. Labelling of some alarms was poor and there was no first up alarm facility. There was a high number of standing alarms (over 10%). There was no evidence of action in response to standing alarms, and in conclusion it appeared these were not monitored or controlled.

- On an installation the importance placed on annunciator integrity in the control room was demonstrably poor. All annunciator lamps were tested and over 100 contained unserviceable lamps. There were a few which had both lamps unserviceable within the same window. The control room operator had no written procedures to guide him in response to process alarms.

3.5.5. Relief / blowdown / flare system integrity

The relief, blowdown and flare / vent collection systems perform a key role in safeguarding against major accidents arising from uncontrolled loss of containment from process plant. The systems typically interact across many parts of the process system and, if impaired, can potentially contribute to significant incident escalation following plant upset or other hazardous events. Some findings from the NIP include:

- On an installation, purge flow to the flares was not identified as being important. Purge monitoring formed part of routine checks but required purge gas amounts were not specified. Checks on site indicated that HP & MP flares had measurable flows, but the LP flare had no indication (alarm only) and the LLP flare had minimal flow with the meter reading near bottom of scale, the control valve almost closed and the pressure indicator broken.

Arrangements to prevent air ingress to relief and flare systems should be in place and be properly specified and routinely and effectively monitored. The importance of this support system to the integrity of the relief and flare system, a major SCE, should not be understated.

- There was no evidence to show that the Level Alarm High-High trip on a Flare KO Drum was functionally tested. Records showed this safety critical device was annually tested only by simulation methods, rather than by raising levels in the drum. The verification scheme included this system in the list of SCEs but insufficient detail was given to direct the verifier into examining a full functional test on this important circuit.

- A flare drum was protected by a 2 out of 3 Level Alarm High-High system. Each switch was mounted on its own independent bridle with isolation valves. However it was noted that these isolation valves were not locked, even though they were listed in the Locked Valve Register. If they had been inadvertently closed it could have led to failure of a safety critical system having potential plant wide effects.

- Pressure Safety Valve (PSV) isolation valves on the LP Flare KO Drum were interlocked. One valve had two keys left in the interlock itself, thereby defeating the system of control.

- During an inspection, operator understanding of functioning of High Pressure (HP) / Low Pressure (LP) interface isolation appeared weak, with dependence upon instrument technician's knowledge of how the protective system worked.

- On another installation there was no system for locking valves at HP/LP interfaces.

All HP/LP interfaces should be clearly identified and adequately protected (e.g. by use of Locked Open valves, or other means to prevent overpressure of the LP system). A preferred action is to conduct a specific HP/LP interface study to identify interfaces and protection assurance requirements. Operators should be made aware of the location and significance of such interfaces and their systems of protection.

3.6 Part 6 – Change control

The control of change requires considerable discipline by all parties to ensure that every element or system affected by the change is adequately addressed. The failure to apply the required discipline has contributed to many of the failures that have occurred on installations.

3.6.1. Change control procedures

Control procedures are needed to provide a formal system for identifying and communicating the need for change, ensuring adequate assessment of the change and managing the implementation process. The change process embodies all the elements of the safety lifecycle from concept selection, design and assessment, construction, commissioning to final operation, inspection, testing and maintenance. A particular feature is the interaction of new or modified systems with design and operation of remaining existing systems. It is to this area where root causes of many accidental events following change can be traced. Some findings from the NIP include:

- The change control scheme for an installation had recently been replaced with a new scheme which had retained a number of shortcomings that rendered the procedure not wholly effective, e.g.;

    - Under the old scheme, master P&IDs were ‘red lined’ with the changes pending formal update of the originals. Under the new scheme, this was not the case and P&IDs were not marked up. Operators were in effect using out of date P&IDs, which was an unacceptable practice.

    - The change procedures provided no clear guide on when a significant risk assessment (e.g. HAZOP) was required.

    - There was nothing in the change procedures to ensure comments from the ICP were taken into account.

    - The change procedure did not indicate the minimum requirements for approving a modification.

    - There was no reference for monitoring and auditing of the change control procedure.

- The change control procedure for an installation did not have a system to reference an initiating engineering query (EQ) to the eventual authorised construction change notice (CCN). The implementation of the change could be a significant time after the authorisation of the CCN. It was not clear from the inspection of a sample of changes how the originator of a change could trace the link between the initial EQ to the authorisation of the CCN, and thence to the final implementation of the change.

The process between initial raising of a change to its final implementation should be capable of being followed from beginning to end through proper referencing.

3.6.2. Roles and responsibilities

Roles and responsibilities for change initiation, approval, communication, monitoring and audit should be defined.

- Examples of change projects were found on an installation where operations personnel input on layout considerations and instrumentation design issues was apparently disregarded without proper feedback to affected parties.

Procedures should ensure that feedback communication on proposals and comment is recorded and outcomes explained.

- Non-compliances against procedures found on an installation involved verbal communication for onshore engineering review of procedural changes, instead of a formal written request, and the use of a non-standardised (albeit appropriate to the task) format for risk assessment of organisational changes.

3.6.3. Hazard identification and risk assessment

Change procedures should ensure that a suitable and sufficient level of assessment is applied to all changes to an installation. This applies to permanent and temporary changes.

- Procedures for an installation covered temporary and permanent changes, deviations from standards and other procedures. The procedure relied heavily on competent individuals exercising their professional judgement. This was important when recognising if a change had wider significance and if other parties should be involved. The production supervisor decided whether a change required a HAZOP. The change procedure did not provide guidance on when a HAZOP was required.

Heavy reliance on individual judgement without clear supporting guidance on key issues such as HAZOP, influence of change, etc. can lead to inconsistent application of change controls and an increased risk of error.

- An installation had a separate procedure for the placing of inhibits, but this did not include a requirement for risk assessment.

3.6.4. Implementation and follow-up

Procedures for change should ensure that actions identified from risk assessment are implemented, tracked and closed out. Documentation affected by the change should be systematically updated and issued to personnel. Outdated drawings should be withdrawn. Example issues arising from NIP inspections include:

- ‘Red line’ drawings showing changes were sent to the shore with a transmittal note for computerised updating. However there was no procedure in place that informed the originator of the ‘red line’ drawings when changes had been made to the computerised ‘as-built’ drawings.

- An example was found where, although the intended purpose of the formal change control procedure had been met, the documentation for implementing change had not always been used. Areas affected included procedural and organisational changes.

- Updated P&IDs - following a modification, recipient copies were up to date but the Operations Supervisor's retained copies were mostly earlier versions and out of date. All controlled documents that are out of date should be subject to a formal disposal procedure and non-controlled versions should not be used.

- In looking at the implementation and follow-up stage of an ongoing change package, inconsistencies in joint tagging were found. Some were tagged with records of torque settings whilst other joints in the system were not tagged. None of the joint tags had been authorised. There appeared to be a discrepancy between procedures used by Maintenance and Engineering departments. Maintenance department used tagging, but Engineering procedures required a listing of details of each joint on a single sheet. There was no system for certification of bolted flanges at the time.

Consistent tagging and recording systems should be applied across departments.

3.7 Part 7 – Maintenance and verification of process safety-critical elements

Management of safety critical elements (SCEs) is an important area. HSE Offshore Division's assessment of incidents suggests that particular attention needs to be given to systems for managing corrosion & erosion and leaks at flanges. Some example findings from inspections are included below:

3.7.1. Process safety critical elements (SCEs)

The inspection of this element was concerned with the identification of SCEs, development of appropriate performance standards and arrangements for integrity assurance and verification. The management of SCEs lies at the core of preventing loss of containment with the potential to cause a major accident. Some of the findings from the NIP include:

- On an installation, performance standards had been set for SCEs. No problems were noted for functionality or survivability. However SCEs for availability and reliability often just stated that systems must be 'available' at all times. There was sometimes little evidence to show that actual levels of reliability and availability were being monitored, e.g. the maintenance system and routines were often recorded as 'completed' without stating what was actually found. Examination and verification by the Independent Competent Person (ICP) indicated that systems often did not achieve this objective. More realistic standards needed to be set that the ICP could establish were being achieved.

- Inspection of an installation found many performance standards that were either unsuitable or not reflected in planned maintenance testing and examination routines for the purpose of verification. Examples included:

    - the active fire fighting system performance standard identified deluge flow rates to be achieved, but no flow measurements were taken during testing.

    - ESDV performance standards specified that a closure time should be stipulated, but no maximum closure times had been assigned.

- A deferral process to justify and authorise planned maintenance activities existed for SCEs where maintenance was outstanding for more than 30 days. The process required authorisation by the onshore technical authority. It was apparent that not all deferrals were communicated to the technical authority but were simply processed at platform level.

It is important that safety critical procedures and authorisations are implemented and effectively monitored. Failure to apply effective monitoring of safety critical procedures can promote a poor safety culture and place integrity of safety critical systems at increased risk.

- There was no system for the installation that allowed the independent competent person ICP to be informed or consulted when safety critical systems were inhibited. This consultation process with the ICP should be included in the management of change procedure.

- There was no company audit scheme that audited the operation of the verification system for SCEs or the way it was being operated by the ICP.

- The maintenance system did not assign the same criticality to individual maintenance tasks as was indicated by the verification scheme. There was no system of control that directed technicians to maintain SCEs first and some SCEs were overdue routine maintenance. There was a reliance on the knowledge and expertise of senior technicians in assigning resources to systems they thought deserved higher priority. A backlog of maintenance existed, some of which included SCEs.

The maintenance of SCEs should be driven by formal controlled schemes and not by informal and uncontrolled opinion of technicians, even if experienced, who do not hold specific responsibility for this function.

- The computerised planned maintenance system did not allow differentiation between maintenance tasks on safety critical equipment and other equipment.

Good practice should allow the status of maintenance for safety critical equipment to be distinguishable from that of other non-critical maintenance to facilitate monitoring. Work priorities should take account of the criticality of the affected plant.

- The Maintenance Supervisor was custodian for verification of the maintenance area, albeit that each Maintenance Technician was responsible for completing the maintenance routines for the SCEs within their discipline. Examination of the maintenance backlog found 37 SCEs for the maintenance section. No formal action had been taken on these items and it was left to the discretion of the technician to complete outstanding work. There was no formal requirement to notify the onshore Compliance Engineer, who later confirmed he was unaware of the backlog.

- Examination of the record of the independent competent person's (ICP's) findings showed a number of findings that had been open for a considerable period ranging between 130 and 1500 days.

There should be an effective system to manage and close out ICP sponsored issues relating to SCEs. Action monitoring should ensure that actions and issues are addressed and / or completed in a suitably short time-scale, proportionate to the risk. Where extended delays occur in closing out actions linked to SCEs, there should be recorded justification for the delay and a periodic review of action completion targets.

- Use of the installation maintenance system was cumbersome and not user friendly affecting management of safety critical maintenance tasks. A 28 day routine look-ahead list showed 16 items ranging from 1 to 22 days overdue. A list for non-routine activities overdue showed 4 entries, ranging from 33 days to 563 days overdue. Some time was accounted for as associated administrative actions, but there was no visible monitoring of these overdue items other than a daily report, which had patently failed to note several of the examples picked during the inspection.

Maintenance systems need to be capable of easily showing maintenance items and by what margin of time safety critical maintenance work is overdue.

- Inspection of an installation found that the computerised information system appeared to be of little use to maintenance personnel, e.g.

- It was not easy to navigate and extracting information was time consuming (e.g. during the NIP inspection it took more than one hour for the maintenance team leader to extract schedule dates and test information on a single tag item, even with help from onshore).

- Work reports seemed to be inspection orientated requiring a tick box input and discouraging valuable text input.

- Database was incomplete, some data having been lost during transfer from the preceding system.

- Overdue list contained jobs that had been completed, or were of unknown origin and status.

- The system contained trip information but, due to the unwieldy system architecture, it was seldom used in favour of other sources of information.

- The maintenance routine instructions were not generated with job cards so that technicians were starved of possible vital information relating to tasks on safety critical systems.

3.7.2. Control of corrosion and erosion

The NIP reviewed the existence of management strategies and their implementation offshore. Example issues arising include:

- External corrosion had been a problem on the separators and a general corrosion under lagging (CUI) monitoring programme had allegedly been put in place. However, as part of a recent vibration assessment on small bore pipework, the contractor had commented that there was much unencapsulated (i.e. inadequately weather protected) insulation on pipework with potential for CUI. It was stated offshore that there hadn't been a specific CUI inspection programme since 1994 apart from the separators. However onshore it was stated that there was a programme in place.

Systems for monitoring the state of CUI on susceptible plant need to be clear and implemented with action taken to protect against CUI by appropriate finishing of lagging installation.

- An installation's corrosion strategy document had not been maintained up-to-date. Corrosion was becoming an increasing problem on the platform and current strategy documentation was essential to define arrangements for proactive risk assessment and management of corrosion / erosion issues.

- Technicians on an installation appeared to lack knowledge of the corrosion management policy.

Implementation of an effective corrosion management strategy should include raising awareness of operations staff of the policy / strategy.

3.7.3. Management systems for flanged joints

The integrity of Bolted Pipe joints over the whole life of the plant should be addressed within the management system. This should be achieved as a matter of management policy by specifically identifying management of bolted pipe joints within the engineering design, construction, maintenance and operation standards and procedures. Training and competence is one of the key elements of joint integrity management. There should be a formal competence assurance scheme, which ensures that competency of all personnel (company and contractor) who are required to work on bolted pipe joints is formally assessed and maintained through periodic reassessment. A register of competent personnel, including contractors, should be kept. Some issues arising from the NIP include:

- Flogging of small flange bolts was still being practiced on some installations. Operators were unaware of HSE Safety Notice 2/2000 addressing this issue demonstrating a failure to communicate safety matters to the workforce. On one installation, current procedures contained reference to the use of flogging spanners – against the recommendations of HSE Safety Notice 2/2000

- An installation's procedures for flange tightening stated that bolt tensioning should be carried out by a 3rd party, but this was not found to be the case in practice. Technicians had been trained to do this work. Technicians were using a different uncontrolled document for this activity. The uncontrolled document being used had different torque values to those contained in the official procedures. It was noted that pipework flanges were not included in the verification scheme.

- Several examples were found of poor assembly practice with flanges being visibly out of alignment even from a distance. This raises issues of competency, awareness of acceptable standards and effectiveness of inspection.

- It was noted that the verification of integrity of critical flange joints was not included as an activity in the verification scheme for the SCE covering hydrocarbon containment systems. A leak had occurred on a piping system which it had been suggested should not have occurred if the correct bolt specification and tightening procedure had been used. It was stated that flanges in the system had been monitored over the year following the incident yet there was no evidence to show that bolt tensions had been monitored during the period following the incident. (Note: UKOOA/IP have produced Guidelines for the Management of Integrity of Bolted Pipe Joints).

- An installation was found to lack a formal competence scheme for making up flange joints. There was no witnessed joint procedure. Another installation lacked a formal procedure for flange make-off, inspection or maintenance.

3.7.4. Review of ageing plant against current standards

Older installations were often designed to standards that have since been superseded. Dutyholders should have arrangements to review their installations against current design standards to determine whether updating is appropriate in line with risk reduction to ALARP criteria.

- On an installation, a significant number of examples of the use of small bore screwed fittings in hydrocarbon (HC) service were found. Piping codes such as ANSI B31.3 would now restrict the usage of such fittings in HC systems. Many of the fittings were on low pressure duty but one was on the outlet of a condensate pump and another had recently been installed in a closed drain system. It appeared that there was a lack of clear strategy on the use of this type of fitting.

- On an installation the quality of valve tagging was found to be variable. New plant was generally well tagged but older plant was not well tagged. Whilst not specifically a hardware issue affecting old plant, this is a safety management issue affecting the consistency of applied controls affecting plant operation.

Dutyholders should seek to apply consistent management and control standards across old and new plant.

- An installation had a 25 year old 36" ESDV actuated by hydraulic power which had a pneumatic interface directed by a single electrically operated solenoid valve. The pneumatic interface had two air operated oil valves, both of which needed to move to the correct position to allow the ESDV TO MOTOR. Hydraulic power, provided by a hydraulic power unit and backed up by accumulators, had to be available to move the valve in either direction. It was found that there had been no SIL assessment done for this system. A generically applied stroke time was used as a maximum allowed stroke time – this was not a nominated performance standard. Records showed that the stroke time was not always recorded. Test intervals were running overdue and other essential checks were delayed.

- These findings demonstrated a need to review older plant and its conformance to current standards.

3.8 Part 8 - Control of miscellaneous process hazards

3.8.1. Sand management

Production of sand can lead to valve seizure or failure affecting ESD function, can inhibit corrosion control regimes and affect the operation of plant, instruments, through solids build-up or erosion, etc. Management arrangements for production solids control should be in place.

- On an installation, there was no clear policy in place for management of risks arising from sand production.

3.8.2. Sampling arrangements

Sampling is a routine activity that involves breaking into the hydrocarbon containment envelope. It is important that clear and effective procedures are developed, that risks are assessed and designated equipment and facilities used. It is particularly important that bad habits do not develop through the lack of definition and monitoring of requirements. Examples were found where the expected level of detail in the management arrangements were insufficient. Some examples found include:

- Operating instructions on sampling were available but lacked detail, including sequence of operations and action in the case of emergency. Several other deficiencies existed including hazard data not being readily available in procedures, manual handling of sampling equipment and access issues, poor lighting, hydrocarbon ventilation issues, etc. suggesting management of the procedures could be improved.

- Company procedures required the use of an earthing strap for sampling using metal containers but the operator did not use the earth strap when observed, though the strap was available for use. The management arrangements for sampling processes should have ensured that procedures and risk assessments were specific in detailing the required safety procedures and that they were implemented in practice.

3.8.3. Air ingress / flammable mixtures in process plant

The prevention of air ingress to hydrocarbon systems during operation and maintenance activities is required to prevent the formation of flammable or explosive mixtures in the system. Examples of deficiencies found during inspections include:

- On an installation, elements of a purge procedure had developed through custom and practice and had not been formalised in procedures. Maintenance procedures should have fully addressed the requirements for system purging for both routine operations and situations requiring special precautions.

3.9 Part 9 - FPSO specific systems

The number of installations falling into this category were relatively few resulting in a limited range of findings. Many of the findings were common with those found on other installations and are not repeated here. However a few findings specific to the FPSO installations inspected are identified below:

3.9.1. Effects of motion on process plant systems

Wave induced vessel movement can affect the performance of process equipment. The operating envelope for process vessels, taking account of vessel movements, should be specified and understood by operational crew, clear instructions should be given to operators on the required action when operating limits are exceeded and such required action should be carried out.

- On an installation it was found that operating procedures existed but did not cover all the operational practices adopted on the installation having the potential to affect vessel motions.

- On an installation the limits for operations were not recorded in the marine operations manual.

If wave induced effects on vessel contents exceed the design performance of process equipment on FPSOs, there can be severe reduction in performance and potentially dangerous effects such as liquid carryover into gas streams to compressors.

3.9.2. Turret arrangements, swivel joints and seals, leakage and recovery

- The design and operational limits of turrets, swivel joints and seals associated with permitting vessel rotation without damage to moorings and risers should be clearly specified and understood by operators. Adequate maintenance and inspection requirements should be applied and recorded.

- The operations manual for an installation specified several levels of inspection and test requirements for hoses and other safety critical components on the turret / swivel assembly. However, examination of the maintenance system to see how these requirements were specified showed none were recorded and there were no inspection records. It was clear that the inspection schedule had not been put into effect and that the verification scheme was not robust to detect this omission.

- Offshore staff on an installation were not aware of any maximum allowable seal leakage rate being set for the swivel and turret.

- An attempt was made to check the verification records for a group of emergency shutdown valves (ESDVs) in the turret. However no records were found for the previous 2 years.

3.9.3. Inert gas controls / cargo tank blanketing

- An installation had no piped ventilation for purging and gas freeing of cargo tanks. This was done through tank-top vents fitted at main deck level and through the main tank entry manholes. The inert gas pressure in the tank was ‘flattened’ to atmospheric pressure, tank tops opened and then manually fitted with ducting and fans. The worke had been risk assessed, but only in respect of potential toxic effects to workers. The assessment had not considered potential explosive atmospheres below the process decking, albeit the work was conducted in the open and consideration of wind direction was made. Risk assessments need to consider all potential hazards.

3.10 Part 10 - Process plant construction and commissioning

Only a small sample of the installations covered by the NIP were in the process of, or had recently undergone, significant projects that could be reviewed at the time of planned inspection. Findings under this category were therefore limited.

3.10.1. Management system

- As part of a major project, reference was made in the safety case to a project Health, Safety and Environmental Plan for the construction project. The plan was said to include a responsibilities matrix, but there was no evidence offshore of the SMS interfacing arrangements, e.g. between the operator and the main contractor.

- A change control procedure was in use, but was a one year old working draft. No formally approved copy of the change control procedure could be produced and it was not clear why an old draft was still in use offshore.

- Inspection of a project found:

  - HAZOP failed to identify fundamental design problems.
  - No procedure to identify ‘safety critical’ flanged joints.
  - No formal procedure to torque/tension joints.

- No formal procedure for issue of materials during construction leading to the wrong material being supplied for an item. This raises issues of training and competency.

- A late additional flange connection was required after the torquing contractor had left site. There were no torquing records for this joint (control of change during construction issue).

3.10.2. Post design

- A platform was undergoing a major modification, was in the final stages of pre-commissioning and the change control process was being strictly adhered to. It was noted during inspection that hydraulic tubing on a number of new systems employed different tubing materials within the same system. This was queried with the construction team who showed that this complied with the hook-up drawings and specifications. However no one on the installation could explain why different materials were in use.

- Whilst close adherence to change procedures was to be commended, personnel should have been aware of unexplained differences and have been prepared to check back to the designers for confirmation of the specification. Consideration could have been given to a simple system of formal recording of construction queries and responses to ensure important design basis information was not lost for future activities.

4 References

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5 List of abbreviations

AFD	Approved For Design
ALARP	As Low As Reasonably Practicable
C&E	Cause and Effect
CAD	Computer Aided Design
CCN	Construction Change Notice
CCR	Central Control Room
CRO	Control Room Operator
CUI	Corrosion Under Lagging
DBB	Double Block and Bleed
EQ	Engineering Query
ESD	Emergency Shut Down
ESDV	Emergency Shut Down Valve
F&G	Fire and Gas
FPSO	Floating Production, Storage and Offloading
HP	High Pressure
HSE	Health and Safety Executive
ICP	Independent Competent Person
IP	Institute of Petroleum
IS	Intrinsically Safe
KO	Knock Out
LC	Locked Closed
LLP	Low-Low Pressure
LO	Locked Open
LP	Low Pressure
LSH	Level Switch High
LSHH	Level Switch High-High
LTI	Long Term Isolation
MHSWR	Management of Health and Safety at Work Regulations
MP	Medium Pressure
NIP	National Inspection Project
OIAC	Offshore Industry Advisory Committee
OIM	Offshore Installations Manager
OTL	Operations Team Leader
P&ID	Piping and Instrumentation Diagram
PC	Programmable Computer
PFEER	Prevention of Fire, Explosions and Evacuation Regulations
psi	Pounds per square inch
PSV	Pressure Safety Valve
PTW	Permit To Work
RIDDOR	The Reporting of Injuries, Diseases and Dangerous Occurrences Regulations, 1995
SCE	Safety Critical Element
SIL	Safety Integrity Level
SMS	Safety Management System
UKOOA	UK Offshore Operators Association