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UNITED STATES DEPARTMENT OF THE INTERIOR

MINERALS MANAGEMENT SERVICES

DEVELOPMENT OF INTEGRITY METHODOLOGIES FOR THE TOPSIDES OF OFFSHORE PRODUCTION FACILITIES

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UNITED STATES DEPARTMENT OF THE INTERIOR

MINERALS MANAGEMENT SERVICES

DEVELOPMENT OF INTEGRITY METHODOLOGIES FOR THE TOPSIDES OF OFFSHORE PRODUCTION FACILITIES

CONTENTS

EXECUTIVE SUMMARY

The objectives of this study were to develop an engineering methodology for topsides structures, plant and piping integrity management and to integrate the survey/inspection process with existing defect assessment procedures.

The work included the collation of pertinent codes, guidance documents, databases and literature worldwide and a number of interviews with the Gulf of Mexico (GOM) offshore industry. This permitted the identification of regulation and code requirements and industry practice.

The Code of Federal Regulations (CFR) prescribes topsides structure inspections in accordance with API RP2A Section 14. However, the CFR coverage of topsides facilities inspection is minimal, the only areas to be specifically noted are cranes, pollution prevention, drilling operations, well completions and safety systems. Few other national or international codes address topsides facilities. Generally, GOM industry practice for topsides inspection is limited to the CFR requirements.

Two relevant topsides related studies have been carried out. They are, the Belmar study that considered risk factors contributing to fires and explosions and the SAMS study that considered operability aspects. However, little work was found which looked specifically at risk based inspection or integrity management of topsides facilities.

A review of topsides facilities anomaly reporting showed two main findings. Firstly, many anomalies are attributable to external corrosion that can be detected by visual inspection, although only a small percentage of these led to failures. Secondly, a high proportion of internal corrosion anomalies led to failure. This leads to the conclusion that visual inspection will detect a high proportion of typical anomalies, but that this alone will not eliminate the anomalies that lead to a significant percentage of the reported failures.

Presented in Section 8 is a suggested alternative methodology for an improved topsides inspection regime, which uses a risk-based approach. The method prioritizes the inspection according to potential risk. This is likely to lead to more inspection of high-risk areas, whilst at the same time reducing inspection from the present requirements where it can be demonstrated that the risk is sufficiently low. An important aspect of the proposed methodology is the utilization of the results of previous inspections in the risk assessment.

It is recommended that a workgroup be formed to take forward the findings from this study in order to develop a practical and usable risk-based approach to topsides integrity management and inspection.

1. INTRODUCTION

1.1 General Background

In recent years, a considerable amount of effort has been expended on the integrity assurance of offshore substructures such as jacket platforms. Detail guidance in this area can be obtained from API and other standards and recommended practices. By contrast, little effort has been directed to date in the field of integrity assurance for topside facilities and no effective link has been established between routine topsides inspection practices (data collection), defect evaluation and the overall integrity management process. It requires, *a priori*, the link between inspection methods and tools and the assessment methodology, i.e. a definition on the information needed from inspection to permit a rational assessment to be carried out.

From the standpoint of integrity of topside facilities, a number of areas of uncertainty exist at the present time, including the following.

- There is a wide range of codes and standards (i.e. regional standards and national standards). The available practices are diverse with little or no cross-discipline interface.
- Existing guidelines for the measurement and recording of degradation mechanisms, in particular, corrosion, are limited.
- Existing guidelines for the evaluation of degradation mechanisms is also limited. Those guidelines that do exist are not well integrated with inspection practices (data collection).
- Performance data from topsides inspections indicates widespread corrosion degradation of appurtenances, including risers, conductors and caissons, through the splash and atmospheric zones. Present routine surveys are ineffective in collecting data necessary to evaluate the significance of the corrosion damage. In addition, assessment methodologies are not well established.
- In the Gulf of Mexico, there is an increasing likelihood of new high temperature/high pressure (HT/HP) production streams being introduced to existing platforms. This introduction places significant emphasis on the need to determine the effects of HT/HP production streams on piping and vessels and the consequential impact on the overall integrity management process.
- Guidelines for the management of topsides anomalies are not captured in any industry-wide format leading to widely varying practices across operators and inconsistent safety indices within the same operating regions.
- The dominant research on integrity of offshore structures over the past decades has focused on jacket structures. The applicability of these research efforts to topside components has yet to be fully examined.
- Extrapolation of present-day relevant practices to cover inspection of topsides has not been examined in any detail. This applies equally to the superstructure (i.e.

deck legs, trusses, girders, risers, etc.) and process/utilities/plant (i.e. system design and layout, pressure vessels, safety critical systems, piping, etc.).

- As with matters related to substructure integrity management, there is an industry – wide recognition of the importance placed on the use of competent personnel to carry out the tasks involved in topsides integrity management. There is a need to define the baseline qualifications and the training for personnel involved in the integrity management of topside facilities.

MMS recognized that a practical integrity management methodology is necessary to facilitate continued asset utilization and field life extension consistent with the health, safety and environmental expectations of industry, regulatory bodies and the public whilst remaining within the economic realities of the modern business world.

MMS appointed MSL Services Corporation (MSL) to study all available codes, standards, guidance documents, appraise current industry practice being followed by major operators/owners, examine available industry database, determine trends and consequences of damage/degradation and present a comprehensive guidance document outlining topsides integrity methodologies.

1.2 Objectives

The objectives of the study are as follows:

- To develop a reliable engineering methodology to manage the integrity of the topsides of offshore production facilities including structural systems, operating plant, piping and appurtenances e.g. risers, conductors and caissons. This objective encompasses the effects of new HT/HP production being introduced to existing platforms.
- To integrate the inspection/survey process (data collection) with existing defect assessment procedures (engineering evaluation) as part of the integrity management strategy.

1.3 Scope of Work

To meet the above objectives the following scope of work was identified:

(a) Collate available, pertinent, documents worldwide, including the following:

- code/guidance documents
- owners documents
- published literature.

(b) Undertake interviews and discussions with the GOM offshore industry.

(c) Undertake an appraisal of documents from (a), from the standpoints of integrity management of topsides facilities, inspection guidelines and damage/degradation evaluation and assessment.

(d) From (b), undertake appraisal of current practice adopted by industry for topsides inspection, to determine operator-specific approaches to topsides inspection with emphasis on survey techniques, data recording and anomaly management.

(e) Establish likelihood of damage/degradation to topsides facilities including structures, operating plant, piping and appurtenances based on MSL in-house Level 1 inspection database and industry feedback.

(f) Establish consequence of damage/degradation to topsides facilities including structures, operating plant, piping and appurtenances based on an assessment of the potential impact to life safety, the environment and business disruption.

(g) Establish effects on piping and vessels of new HT/HP production being introduced to existing platforms, and the likelihood and consequence of damage/degradation.

(h) Based on the likelihood and consequence of damage/degradation, develop a criticality ranking of the relevant components of the structure, operating plant, piping and appurtenances, based on a risk assessment approach and the identification of Safety Critical Elements (SCEs).

(i) Produce improved Level 1 survey procedures focused on the critical topsides components with suggested survey techniques and data recording methods.

(j) Provide a guideline for the integrity management of topsides facilities integrating the life-cycle processes of data management and collection, data evaluation, integrity strategy and inspection program. Describe the baseline levels of qualifications and training necessary for personnel engaged in the integrity management of topsides facilities.

1.4 Methodology

The scope of work was carried out in-house, using established procedures for studies of this nature. The data and information was captured using MSL's in-house library facilities and on-line computer links with library systems worldwide, and augmented by using MSL's established contacts in this field. The database of results of Level 1 inspection surveys resides on MSL computers.

Interviews with the GOM offshore industry were carried out in Houston, New Orleans and Lafayette. MSL has established contacts with various organizations, and MMS advice was sought in the selection of organizations. A questionnaire was prepared prior to the interviews, in order to ensure that the interviews remained focused on the target objectives. Detailed interview notes were created for use in the study.

Engineering appraisal, determination of likelihood/consequence of damage/ degradation, criticality ranking and guidance creation was carried out using in-house procedures and processes.

2. REGULATIONS, CODES AND STANDARDS OF PRACTICE

2.1 Regulations

2.1.1 General

Inspection of Gulf of Mexico oil and gas facilities in the Outer Continental Shelf (OCS) falls within the scope of Title 30 Code of Federal Regulations (CFR), Chapter II, Part 250. In addition to the specific requirements found there, the regulations incorporate certain provisions from recognized industry codes and practices, which are listed in 30 CFR 250.198 [(1)].

2.1.2 Topsides Structure

The regulatory instrument under which all fixed platforms installed in the OCS shall be inspected is 30 CFR 250.912 [(2)]. The cited clause calls for all platforms to be inspected periodically in accordance with the provisions of API RP2A [(3)], Section 14 (Surveys). However, use of an inspection interval that exceeds 5 years shall require prior approval by the Regional Supervisor (of MMS). Proper maintenance shall be performed to assure the structural integrity of the platform as a work base for oil and gas operations. 30 CFR 250.912 also requires a report to be submitted annually on 1 November to the Regional Supervisor stating which platforms have been inspected in the preceding 12 months, the extent and area of inspection, and the inspection methods used. The report is also to contain a summary of the results, what repairs if any were required, and a statement on the overall condition of the platform.

The regulatory provisions for inspection of other types of platforms (e.g. tension leg platforms, floating production systems, etc.) fall under the jurisdiction of the US Coast Guard (USCG) Marine Safety Manual [(4)], supplemented by USCG Policy Letter No. 03-01 [(5)]. Many of these types of facilities would be expected to follow class rules requirements.

2.1.3 Operating Plant and Piping

The level of inspection for topsides facilities required by the Federal Regulations varies according to the type of equipment or system function. Of particular concern are platform cranes, pollution prevention, drilling operations, well completions, and safety systems.

Platform Cranes

Platform cranes must be maintained in accordance with 30 CFR 250.108 [(6)], and API RP 2D [(7)].

Pollution Prevention

With regard to platform facilities, there are few prescriptive inspection requirements (other than those relating to safety systems) but there is a general onus in 30 CFR 250.300 [(8)] to operate all hydrocarbon-handling equipment for testing and production such as separators, tanks, and treaters so as to prevent pollution. "Maintenance or repairs which are necessary to prevent pollution of offshore waters shall be undertaken immediately" (§ 250.300(a)(3)). "Drilling and production facilities shall be inspected daily or at intervals approved or prescribed by the District Supervisor to determine if pollution is occurring. Necessary maintenance or repairs shall be made immediately" (§ 250.301(a)).

Drilling Operations

The main drilling inspection issues relate to the operation of the blowout preventer (BOP) as prescribed in 30 CFR 250.446 [(9)]. The code incorporates by reference API RP 53 [(10)] Sections 17.1 and 18.1 Inspections, and as well as calling for daily visual inspection of surface BOPs (§ 250.446(b)).

Well Completions

Again the main concerns are the testing and inspection of the BOP, which are addressed in 30 CFR 250.516 [(11)]. BOP testing is required at least every 14 days (§ 250.516(a)(2)). Visual inspection must take place at least daily, weather permitting; television cameras may be employed for this (§ 250.516(g)).

Production Safety Systems

30 CFR 250.802 [(12)] requires that "All production facilities, including separators, treaters, compressors, headers, and flowlines shall be maintained in a manner which provides for efficiency, safety of operation, and protection of the environment" (§ 250.802(a)). All platform production facilities with a basic and ancillary surface safety system shall be tested, and maintained in operating condition in accordance with API RP 14C [(13)] (§ 250.802(b)).

All surface safety valves (SSVs) and underwater safety valves (USVs) shall be inspected, installed, maintained, and tested in accordance with API RP 14H [(14)] (§ 250.802(d)).

Pressure and fired vessels are to be designed, fabricated, code stamped, and maintained in accordance with applicable provisions of sections I, IV, and VIII of the ASME Boiler and Pressure Vessel Code [(15, 16, 17)] (§ 250.803(b)). Pressure relief valves shall also be maintained in accordance with the applicable provisions of this code (§ 250.803(b)(i)).

Other safety devices are to be inspected and tested at intervals not greater than laid down in § 250.804 "Production safety-system testing and records". These include safety and shutdown valves, and pressure, temperature and level sensors.

2.2 Codes and Standards for Topsides Structure

A review [18] of inspection practices covering both fabrication and in-service inspections for topsides structural components was recently carried out by MSL for the U.K. Health and Safety Executive (HSE). A search was made of technical indices and reference sources to identify codes and standards that may or could be used for the inspection of offshore structures. The search identified a number of international, pan-national and national documents [3, 19, 20, 21, 22, 23, 24, 25, 26, 27, 28, 29, 30, 31, 32] that were studied to identify clauses relevant to:

i. Material classification issues.
ii. Categorization of components.
iii. The recommended inspection techniques including procedures, inspector qualifications and reject/acceptance criteria.
iv. In-service inspection requirements.

A summary of the content of the documents is given in Table 2.1. The table indicates whether each document has anything relevant to the above items and if so, to what qualitative level of detail does the document address the item.

It can be seen from Table 2.1 that the extent of coverage by the documents is quite variable. The NORSOK set of standards and the forthcoming ISO 131819-2 offer the most coverage. Both of these codes are new codes. The most prevalent offshore standard, API RP2A, has something on all items but is rather limited in depth. In-service inspection is poorly represented with most codes having nothing or only little to say on this aspect. Much that does exist appears to be based on or attached closely to the associated inspection of the sub-structure. Only ISO 13819-3 (the topsides Annex) attempts to give some practical guidance on in-service inspection but even then it is limited.

Each document was examined to provide an understanding of the level to which it addressed the following attributes in relation to the inspection requirements relating to the in-service condition:

a. Material classification in relation to component duty.
b. Inspection techniques, procedures and qualification.
c. Critical classification.
d. Complexity identification.
e. Extent of inspection and how allocated.

The findings of this examination with respect to the API, NORSOK and ISO codes taken individually are summarized in APPENDIX A. Here, a comparison between the codes is given.

Document	**Material Classification**	**Component Classification**	**Inspection Techniques**	**In-service Inspection**
API RP2A	Limited	Limited	Little	Little
EEMUA No.158	Limited	Limited	Detailed	No
NORSOK	Detailed	Detailed	Detailed	Little
ISO 13819-1	No	No	No	Little
ISO 13819-3	Limited	Little	No	Limited
ISO 13819-2	Detailed	Detailed	Limited	Little
DD ENV 1993-1-1	Little	Little	Little	No
DD ENV 1090-1	Little	No	Limited	No
ISO/FDIS 10721-2	Little	Little	Detailed	No

Coverage:

No: The document makes no mention of the item.

Little: The item is mentioned as an aspect that needs consideration but little guidance is given within the document.

Limited: There is some guidance given but it is not particularly detailed. It may, for instance, give a list of issues that are involved but without any weighting as to the importance of the issues.

Detailed: As implied, the guidance is detailed and more or less complete. Typically, tables of categories are presented within the document.

Table 2.1 Comparison of coverage of various topside structural codes according to selected subject matters

2.2.1 A comparison of in-service inspection requirements

For in-service inspection of topside structures the standards provide far less guidance than for fabrication inspection. This is not necessarily illogical. Following from the practice of onshore structural design, safety is very much a design and fabrication issue. It is implicit that the structure will operate with minimal inspection or maintenance for the duration of its working life.

Most of the standards that were prepared for the design and fabrication of offshore structures include a specific provision for a "bench mark" inspection of the platform structure as soon as practicable after installation. This is generally defined as a substructure issue with a token "look-over" for the topsides. Such an inspection has several functions – included in which is a practical check on the integrity of the design. No QA system is foolproof. Even for a platform that has been designed and approved for zero in-service inspection this initial inspection has an intrinsic value that should not be dispensed with. Unfortunately none of the standards attempt to identify the timing of such an inspection with respect to the commissioning of the platform's equipment. The commencement of drilling operations and the on-loading of bulk materials, together with the thermal and dynamic loads in risers and process systems, could all initiate a hidden weakness in the structural systems that would not be evident otherwise. The requirements for the benchmark inspection of topsides should ideally address these issues.

The frequency of subsequent in-service inspections for topsides generally follows as an add-on to that for the substructure. This is likely to be both inefficient and ineffective for topsides. The "Structural Integrity Management Plan" would include requirements for topsides that relate specifically to the in-service criticality of components.

Default periodic inspections during the planned life of the structure are noted in ISO 13819-2 and API RP2A-LRFD, which are linked to the exposure level and/or type of structure (i.e. manned/unmanned etc.). For such cases the type of inspection involves mainly underwater inspections of the substructure, involving the use of divers/ROV and also for detail NDT inspection the use of techniques such as FMD. Hence, the nature of these types of inspection is not applicable to the requirements for topsides.

The only standard which provides any form of an inspection program for topsides is ISO 13819-1.3, as shown in Table A.6 of APPENDIX A, which follows a similar pattern to the ISO 13819-2, default program (i.e. periodic inspection levels). As stated in Appendix Section A.6, the default program is linked to particular areas (i.e. coatings, safety critical elements and missing/damaged members). The standard emphasizes the need to consider topside components, which may require special attention, but such details are given in the informative section. Furthermore and as noted in Section A.6, limited guidance on selection of inspection techniques is given with respect to components that have protective coatings. The periodic inspections identified involving NDT inspection require different degrees of inspection of safety critical elements varying from 10% to 100% depending on the level of inspection required. The basis of the 10% value is unclear and further information to support this would be desirable.

NORSOK N-005 also defines that an initial condition survey during the first year of operation is recommended followed by a "framework program" for inspections on a 3-5 year cycle (Cl.5.3.1), based on the experience obtained from Norwegian petroleum activities. Alternative Instrumentation Based Condition Monitoring (IBCM) is also highlighted in NORSOK N-005 as being an alternative to conventional inspection methods. The IBCM is considered to be suitable to areas with limited accessibility for performance of condition monitoring and maintenance.

It is clear that with respect to the level of inspection required (i.e. extent and type of techniques) that no similar correlations with fabrication requirements are explicitly given. Therefore, one could assume that the type of technique(s) used and the extent of coverage may not be similar to the minimum requirements adopted during fabrication. Selection of inspection techniques may need careful consideration particularly for components requiring inspection that have protective coatings.

A particular issue in relationship to in-service inspection is that criticality is a time based variable. Some very large structural elements, critical to transport and lifting, may, once the platform is complete offshore, be redundant and have low levels of utilization. Many large and impressive components of major platforms could in fact be removed completely after installation but are likely to be subject to considerably more offshore inspection than a support on a critical riser or process vessel. Most modern offshore platforms – even those on four main supports – could tolerate the loss of a support or the column or brace directly above it without initiating a life-threatening event.

However, none of the codes give clear systematic guidance or instruction on the assessment of system interaction between structure and process plant/pipework although this issue is raised in ISO 13819-1-3 (in Cl. 16). When one considers that the pipe work can consist of up to 2-meter diameter tubes – an order of magnitude stiffer than some of the "supporting" structure – and may contain explosive liquids and gases at pressures exceeding 200bar, with complex routing, this omission is clearly undesirable. When one adds the practice of analyzing the pipes and supporting structures in completely independent models with no systematic exchange of stiffness data the need to ensure high quality in the supporting systems is very clear. The supports on major pipes and vessels are likely to present considerably less redundancy and a more severe consequence of failure. The system is critical, complex and poorly understood.

2.3 Codes and Standards for Operating Plant and Piping

The following Table 2.2 is a comparison between the various process facility codes and standards of practice.

Document	Description of the Document	In-service Inspection
30CFR250.198[1]	List of recognized industry codes and practices.	-
30CFR250.108[6]	Refers to & API RP 2D[7] -Operation and Maintenance of Offshore Cranes", 4th Edition, August 1999.	-
30CFR250.300[8]	Refers to pollution prevention and control	-
30CFR250.446[9]	Refers to API RP 53 [10] - What are the BOP maintenance and inspection requirements?, July 2003.	**Daily**
30CFR250.516[11]	Refers to blowout preventer system tests, inspections, and maintenance, July 2003	**2 weeks**
30CFR250.802[12]	Design, installation, and operation of surface production–safety systems, July 2003	-
30CFR250.802b[12]	Refers to API RP 14C [13] - Analysis, Design, Installation, and Testing of Basic Surface Safety Systems for Offshore Production Platforms", 7th Edition, March 2001	-
30CFR250.802d[12]	Refers to API RP 14H[14] Installation, Maintenance and Repair of Surface Safety Valves and Underwater Safety Valves Offshore", 4th Edition, July 1994.	-

Table 2.2 Comparison of Various Process Facility Codes

30CFR250.803b	Refers to ASME Boiler and Pressure Vessel Code Sections I, IV and VIII [15, 16, 17]	-
30CFR250.804	Refers to Production and Safety System Testing and Records	-
30CFR250.912[2]	Refers to the API RP 2A[3] for Structural Inspections	Topsides 1 year & jacket 5 years
API 510[34]	Subsection 6.6 calls for pressure relief devices to be inspected and tested at intervals not exceeding 5 years and in accordance with API RP 576[6].	Not to exceed 5 years
API 570 [36]	Inspection frequency of piping based on corrosion rates	-
API RP 572[33]	Recommended practice for the inspection of pressure vessels operating at pressures above 15 psig. Depends on corrosion rate and remaining life.	i.e.,15 years or ½ remaining life, etc.
API RP 574 [35]	Recommended practice for the inspection of piping, tubing, valves (other than control valves) and fittings. Depends on Class of circuit, corrosion rate and remaining life.	i.e., 5 years or ½ remaining life, etc.
API RP 576 [37]	Pressure relief device testing and maintenance	-
API RP 579 [40]	Contains guidelines and methodology for the quantitative assessment of flaws and damage found in operating pressure systems	-
API RP 580 [41]	RBI. Justifies modification to inspection frequencies as provided for in API 510[34], API 570 [36] and API Std 653 [38].	-
API Publ 581 [42]	Provides essential data and working procedures for evaluating risk as part of an RBI program.	-
API Std 650 [39]	Storage tanks	-
API Std 653 [38]	Inspection and maintenance of atmospheric storage tanks	-

Table 2.2 Comparison of Various Process Facility Codes (Cont.)

2.3.1 Pressure Vessels

API RP 572[33] presents the recommended practice for the inspection of pressure vessels operating at pressures above 15 psig. Included in this category are towers, drums, reactors, heat exchangers, and condensers. The document includes sections on reasons for inspection, causes of deterioration (corrosion, erosion, metallurgical and physical changes, mechanical forces, faulty materials or fabrication), frequency and method of inspection, and methods of repair. For inspection frequencies based on corrosion-rate determination, API 510 [34] Pressure Vessel Inspection Code is applicable. This permits an inspection interval based on the calculated remaining life of the vessel in question. Cl.8.3.4 allows vessels to be categorized into lower or higher risk classes, which determine the actual inspection frequency. The parameters to be considered are:

- Potential for vessel failure: minimum design temperature, cracking, corrosion, erosion;

- Vessel history, design and operating conditions: repairs, alterations, age, corrosion allowance, fluid properties, operating pressures and temperatures;

- Failure consequences: location relative to personnel, equipment damage, and environmental consequences.

Cl.8.3.1 permits on-stream (external NDT) or visual internal inspection to be used interchangeably. Inspection frequencies are defined in Cl.8.3.5 and are given below (Table 2.):

Risk Category	Visual Internal *or* On-stream (external NDT)	Visual External
Higher Risk	*Corrosion-rate life ≥ 4 years:* Lesser of: • 15 years • ½ remaining life *Corrosion-rate life < 4 years:* Lesser of: • 2 years • Full remaining life	At time of internal/on-stream inspection *or* At shorter intervals (owner's discretion)
Lower Risk	*All corrosion-rate lives:* Lesser of: • 15 years • ¾ remaining life	At time of internal/on-stream inspection *or* At shorter intervals (owner's discretion)

Table 2.3 Pressure Vessel Inspection Frequencies (API 510)

For lower risk vessels, inspections may be undertaken on a representative sample of vessels in that class.

2.3.2 Piping

API RP 574 [35] presents the recommended practice for the inspection of piping, tubing, valves (other than control valves) and fittings. The document includes sections on reasons for inspection, inspection for deterioration in piping, including corrosion monitoring and various specific types of corrosion and cracking, frequency and methods of inspection, and determination of retirement thickness (for piping, valves and flanged fittings).

For inspection frequencies based on corrosion-rate determination, API 570 [(36)] Piping Inspection Code is applicable. This permits an inspection interval based on the calculated remaining life of the vessel in question. Subsection 6.2 requires piping systems to be categorized into one of three classes.

Class 1: *Highest potential of resulting in an immediate emergency if a leak occurs:* flammable services prone to brittle fracture / rapidly vaporizing streams / H_2S streams;

Class 2: *Services not in other classes:* slowly vaporizing streams / fuel gas / natural gas;

Class 3: *Services that are flammable but do not significantly vaporize when they leak and are not in high activity areas:* hydrocarbons operating below the flash point / distillate and product lines to and from storage.

Inspection intervals are dependent, *inter alia*, on the remaining life calculations, piping class, applicable jurisdictional requirements, judgment of responsible personnel, and previous inspection history. Maximum intervals are defined in Subsection 6.3 and in Table 6-1 of the Code, as summarized below (Table 2.4):

Type of Circuit	Thickness Measurements (External NDT)	Visual External
Class 1	Lesser of: • 5 years • ½ remaining life	5 years
Class 2	Lesser of: • 10 years • ½ remaining life	5 years
Class 3	Lesser of: • 10 years • ½ remaining life	10 years
Injection points (Cl.5.3.1)	3 years	By Class

Table 2.4 Piping Inspection Frequencies (API 570)

Injection points can be susceptible to higher rates of corrosion and are therefore treated separately.

2.3.3 Pressure Relief Devices

API 510 [34] Subsection 6.6 calls for pressure relief devices to be inspected and tested at intervals not exceeding 5 years. They should be tested and maintained in accordance with API RP 576 [37].

2.3.4 Atmospheric Tanks

API Std 653 [38] is widely used for the inspection and maintenance of atmospheric storage tanks. It includes sections on inspection (external, internal and frequency), examination and testing in accordance with API Std 650 [39].

2.3.5 Fitness for Service

API RP 579 [40] provides extensive guidelines and methodologies for the quantitative assessment of flaws and damage found in-service within pressurized systems. The guidelines can be used “to make run-repair-replace decisions to help ensure that pressurized equipment containing flaws which have been identified by inspection can continue to operate safely” (Section 1). Anomalies addressed are brittle fracture, metal loss, pitting, blisters, laminations, weld misalignment, shell distortions, crack flaws, and creep.

Appendix A of the guidelines provides calculation methodologies for pressure vessels, piping components and API Std 650 storage tanks. Computations made accordingly determine the maximum allowable working pressure (MAWP) accommodating the flaw.

2.3.6 Risk Based Inspection

API RP 580 [41] is the recently developed recommended practice for performing risk-based inspection (RBI). The procedure requires careful examination of each system component to determine both the likelihood (probability) and consequence (harm to personnel, environment and asset) of any failure.

Risk is defined as the product of the two parameters. Each equipment item can therefore be ranked according to its computed risk. Failure probability is dependent both on intrinsic characteristics such as component material, fluid service, and operating conditions, but also on extrinsic actions such as frequency and type of inspection. It is therefore possible to mitigate an unacceptable risk by increasing either the frequency or intensity of inspection, until the resultant risk is within acceptable bounds. Conversely, the inspection frequencies of very low risk items may be safely reduced, thus bringing an economic advantage as well as certain safety benefits. Firstly, inspection personnel will be less exposed to harm and secondly, where intrusive inspection methods are needed, there is less chance of operator or fitter error.

API RP 580 does not replace existing codes, but justifies modification to inspection frequencies as provided for in API 510 [34], API 570 [36] and API Std 653 [38]. The practice is concerned with pressure containment *only* of the following equipment types (Cl.1.2.4):

a. Pressure vessels – all pressure containing components.
b. Process piping – pipe and piping components.
c. Storage tanks – atmospheric and pressurized.
d. Rotating equipment – pressure containing components.
e. Boilers and heaters – pressurized components.
f. Heat exchangers (shells, heads, channels and bundles).
g. Pressure relief devices.

The document is *not* concerned with the following non-pressurized equipment types (Cl.1.2.5):

a. Instrument and control systems.
b. Electrical systems
c. Structural systems.
d. Machinery components (except pump and compressor casings).

The lower list usually falls within a reliability-centered maintenance (RCM) program. Thus RBI is *complementary* to RCM, rather than an alternative.

API Publ 581 [42] provides essential data and working procedures for evaluating risk as part of an RBI program.

2.3.7 Visual Inspection of Other High Risk Fire and Explosion Hazards:

As pointed out in section 4.2.9, a previous study [51] carried out on behalf of MMS examined fire and explosion incidents in the Gulf of Mexico and found that one major cause was electrical shorting. Visual inspection for loose wires and highly corroded electrical junction boxes may help reduce this Fire and Explosion Hazard.

2.4 Codes and Standards for Coatings

There is little guidance relating to the in-service inspection of coatings. Almost all references to inspection of coatings in the literature were found to concern inspection during, or immediately after, the application of the coating. However, the Society for Protective Coatings [43] has published a guide to assess the condition of (general, spot or pinpoint) rusting on painted surfaces. The guide gives example photographs to classify the coating condition.

3. DATA AND INFORMATION SOURCES

3.1 Introduction

A variety of sources have been used in performing this study, which broadly can be categorized as follows:

- Literature
- Internet searches
- In-house inspection data
- Externally sourced inspection data
- Operator procedures
- Information obtained from interviews with operators and contractors.

These are generally referred to within the text as appropriate. Two sources, specific to the study, were the external inspection data and the interviews. These are discussed further below.

3.2 Externally Sourced Inspection Data

To assist in the determination of defect frequencies and failure probabilities, MSL acquired from Global X-Ray & Testing Corporation (of Morgan City) a Gulf of Mexico mechanical integrity database [(46)], comprising 1,960 anomalies recorded in the period 1995-2003. The information was contained in an Excel spreadsheet.

The following is a description of the data provided:

1) DATE IDENTIFIED - Depending on the client, either the date of the survey that detected the deficiency or the date that the client was notified of the deficiency.

2) CIRCUIT ID - An alphanumeric label, which together with the client and facility, uniquely identifies each vessel or piping circuit in the mechanical integrity database. The circuit ID is one which has already been established on process and instrumentation drawings (P&IDs) and is in use by the field operating personnel. All vessels not previously designated are assigned an item name in accordance with API RP 14C. Sections of piping are broken up into circuits, which are defined as continuous sections of piping with a common design pressure. Piping associated with a vessel is assigned the vessel circuit ID followed by letter indicating the service of the circuit, e.g. MBD-1000-I is the Inlet piping circuit associated with the MBD-1000 vessel, or an integer, e.g. MBD-1000-2 is the second piping circuit associated with the MBD-1000 vessel.

3) DESCRIPTION - a brief description of the vessel or piping circuit.

4) EQ TYPE - classification of equipment into 1 of 3 categories, Vessels, Piping, and Tanks. Note that initially, the database did not contain a Tank category, so some tanks were categorized as Vessels.

5) PRIORITY - Notes if the deficiency is a failure, or the degree of severity (1-3). Due to variations in clients' mechanical integrity programs, there is some variation in priority classification. In all cases however, Priority 1 deficiencies are the most critical, and Priority 3 deficiencies are the least critical. Priority 1 deficiencies are usually associated with severe deterioration and/or high potential for failure, and are usually reported immediately upon being identified by the technicians performing the survey. Priority 2 deficiencies are normally associated with lack of overpressure protection, and typical Priority 3 issues are as follows:

a) The equipment is not fit for design pressure but is fit-for-service at the current relief pressure.
b) The equipment has high corrosion rates or less than 1 year of remaining life for design pressure based on remaining corrosion allowance and calculated corrosion rates.
c) The equipment is fit for design pressure but has components with thickness less than the client's recommended structural minimum thickness.
d) The equipment requires servicing to continue operating safely or prevent further deterioration (e.g. heavy external corrosion that needs to be addressed).

Note that the same deficiency may appear more than once with different priorities. This occurs when equipment with Priority 1 or 2 deficiencies is removed from service rather than repaired, or when overpressure protection is lowered below the calculated MAOP while replacement equipment is being fabricated.

6) DESIGN PRESSURE - the pressure to which the circuit was evaluated to determine the minimum required thickness of each component. For vessels, this is the maximum allowable working pressure (MAWP) stamped on the vessel nameplate. If the vessel has no nameplate, or the design pressure cannot be read from the nameplate or any available documentation, the safety relief valve set pressure is used as the design pressure. When available, the design pressure for pipe circuits is obtained from PFDs/SFDs, otherwise, the design pressure is the pressure rating of the flanges at the design temperature, or the MAWP of the vessel in cases where the stamped MAWP of the associated vessel is less than the pressure rating of the piping flanges at the design temperature and the piping cannot be exposed to a higher pressure than the stamped MAWP of the vessel

7) OPERATING PRESSURE - the high end of the normal operating range of the component surveyed.

8) RELIEF PRESSURE - the set pressure of the relief valve(s), burst plates, and any other secondary pressure limiting safety devices in the system. For flowlines, this may be the shut in tubing pressure of the well.

9) MAOP - the calculated maximum allowable pressure based on wall thickness, type of steel, geometric properties, and joint efficiencies. The MAOP is defaulted to the design pressure if the calculated allowable pressure is higher than design.

10) DEFICIENCY - A brief description of the deficiency.

11) CAUSE --- A 2-letter code indicating the primary cause of the deficiency as follows:

FI – Faulty Installation
IC – Internal Corrosion
IE – Internal Erosion
EC – External Corrosion
WD – Weld Defect

Note that in many cases, a deficiency may have 2 or more contributing factors. In all cases, the primary contributing factor is indicated.

12) RECOMMENDATIONS--- Recommended corrective actions.

13) ABBREVIATIONS – Below is a listing of unfamiliar abbreviations that may be encountered in the database.

CUI – Corrosion Under Insulation
F/L – Flowline
HAZ – Heat Affected Zone
LO/TO – Lock Out / Tag Out
OOS – Out of Service
P/L – Pipeline
SCH - Schedule
SITP – Shut In Tubing Pressure of a Well
Tmin – The higher of the minimum required thickness for the design pressure or the Client's recommended structural minimum thickness
TML – Thickness Measurement Location
TOL – Thread-O-Let

The data was used in deriving failure likelihood presented in Section 4.2 below.

3.3 Information obtained from Interviews with Operators and Contractors

Since the widest view of industry practice on topside Level I surveys is held with the companies that do the majority of topside inspections, MSL interviewed these Level I inspection companies. Please note the following Level I inspection company interviews.

3.3.1 Interview with Gary Kane of The Kane Kompany:

The Kane Kompany
254 30th Street
New Orleans, LA 70124
Ph: (504) 488-6643
Fax (504) 488-0931
GARY KANE
gkane@thekane.com

Gary says that of the 15 different companies that his company works for, that only three of the companies have their own inspection specifications or inspection scopes of work. His company has inspected over 400 platforms in the GOM. He says that the rest of the operators just ask him to carry out "Level 1" topside surveys and tell him where and when to meet their transportation. Gary supplied the attached example of one of their recent reports to give us some idea of the type of report they put together when the client has no specification.

Gary says that Kane Kompany does not have Level I inspection specs but inspects the following Level I items:

Deck to pile connection, walkways, handrails, +10 above and below, risers and riser clamps and riser isolation, conductor guides, conductors installed, significant conductor movement, MMS paint grading which covers three levels of coat loss and three levels of metal corrosion, boat landings, riser guards, deck structural and cellar deck height above the sea surface.

The Kane Kompany takes CP readings at diagonally opposite jacket legs and at risers. They also determine if the risers are isolated or not.

They do not do USCG checks like: nav aids, swing ropes, helideck safety nets, etc.

3.3.2 Interview with Jim Briton of Deepwater Corrosion Services, Inc.:

10851, Train Court
Houston, TX. 77041 USA
Jim Britton (jbritton@stoprust.com)
Tel: (713) 983-7117 ext. 225
Fax: (713) 983-8858
Cell: (281) 744-5806

Jim Britton, of Deepwater Corrosion, feels that in additional half an hour or hour of inspection time per platform would be required for a level 1 inspection to be expanded more and to collect more important information about the structural integrity and the condition of the process facilities on the upper levels of the deck.. He recommends that the inspection work, his company performs for two majors, be the norm throughout the Gulf of Mexico. His trained inspectors looks at the piping, process facilities, handrails, grating and stair treads that need to be repaired or replaced on these platforms. He normally estimates area of grating, number of handrails and the quantity of stair treads that need to be replaced. His trained inspectors also estimate the surface area of the platform needing re-painting based on the inspector's trained knowledge of when paint really needs to be re-done. He indicates that only a small portion of most decks need re-painting and that area he indicates in his reports. He points out that well bay area corrosion, after drilling, is usually extremely high due to the highly corrosion chemicals being used in the drilling operations.

Jim said that his company has carried out level 1 topside surveys on over 2500 platforms in the GOM for over 130 oil companies. He keeps all his data on all the platforms on Access including photographs, reports etc. He says he keeps detailed records on all of these platforms. He says that almost all the operators he works for do not have specs or a scope of work for these level 1 surveys, except BP. He says Deepwater Corrosion's own inspection scope is the spec he follows and that he supplies his spec in his bid proposals. His agreement is then based on Deepwater's own proposal's spec and scope of work. . Jim says there is little profit on these "Level 1" surveys. He just does it as a service to the industry and a way to keep his men busy. He says that one of his men usually does about 4 "Level 1" surveys in a day. He says his survey approach is risk based and that is how he is able to do the surveys so fast. His surveys focus on the high-risk areas of the platform. He says his clients do not talk about using a risk based inspection approach unless it is one of the majors he deals with or its MSL.

Deepwater Corrosion has very good Level I inspection specs. MSL has reviewed a copy of Deepwater Corrosion's Level I spec – Risk Based Platform Inspection Procedure and an example inspection report.

<u>Deepwater Corrosion Level I Surveys include:</u>

1. C.P. readings at risers, diagonally opposite jacket legs and inside water handling process vessels.
2. Emphasis on the following areas for inspection given by Deepwater Corrosion Services:
    - Cathodic protection, structural condition, leak and spill prevention.
    - Risers, riser clamps and electrical isolation
    - Paint inspections follow the Steel Structures Painting Council (S.S.P.C) ratings.
3. The inspections check the Barge bumpers, boat landings, bridges, conductors, crane pedestals, deck to pile connections, deck beams, flare tower deck connections, grating, handrails, heliport decking, heliport safety shelf, riser supports/protectors, saltwater casings/supports, quarters, generators and compressor connections to the deck, stairways, swing rope connections, truss row members and tubular structure members.

3.3.3 Interview with Bing Strassburg of Oceaneering Solus Schall:

Oceaneering Solus Schall
11925 Fm 529 Rd.
Houston, TX 77041
Attn: Robert "Bing" Strassburg
Direct: 713-329-4771
Mobile: 832-368-3896
Bing@oceaneering.com

MMS Level 1 Inspection interview with Bing Strassburg, March 8-9, 2004.

Solus Schall does about 2000 Level I inspections / year on US GOM platforms and has done so for over 10 years.

Solus Schall says they normally do not report on process or process piping problems unless they see something obviously bad.

They can inspect on other things not normally included in the default level 1 surveys like: process piping, paint, wall thicknesses, corrosion handrail strength, USCG inspections, etc. They do not estimate the amount of grating that needs replacing or the number of handrails, but can do this work.

Solus Schall test handrails, for example, for a major, for the ability to handle 700 pounds of lateral load.

They normally do not carry out wall thickness checks, but Solus Schall thinks that should be done if pitting or severe corrosion is found.

Oceaneering Solus Schall also supplies a Oceaneering Solus Schall level I spec to its clients on which it bases its normal Level I inspections. This spec includes a topside visual inspection looking at paint, handrails, grating, stair treads, swing ropes, etc. If they see paint or something structural that needs an engineer, they recommend to their customer that an engineering specialist is called out to investigate further as an extra to their normal Level 1 survey.

MSL has noted below the things required for inspection under Oceaneering Solus Schall's "Client Version Level I Survey Procedure".

1. Topside inspections (coatings and structural).
2. C.P. surveys.
3. Risers/J-tube surveys (diameter, location, corrosion damage, clamps, etc.
4. Conductor surveys (diameter, slot, corrosion damage, shims, conductor movement, status-out of service, P&A's.
5. Subsidence or differential settlement.
6. Anomaly/ repairs.

7. Photographic log.

Solus Schall grades the condition of the coatings and the structure underneath as good, moderate or bad.

3.3.4. Interview with Galvotec Corrosion Services:

Galvotec Corrosion Services, LLC
300 Bark Road, Bldg. C-2
Harvey, LA 70058
Ph: 504-362-7373
Fax: 504-362-7331
James Brandt

Galvotec usually carries out Level I surveys on about 400 platforms a year for about 20 operators. Galvotec said that generally only the major oil companies speak about Risked Based Inspections, which represents about 20% of the platforms inspected. The other 80% of the inspections were carried out for companies that do not require or specify Risked Based Inspections. These companies just wanted normal Level I inspections required by the regulations. A few majors and one independent he does work for have requested additional inspections beyond Level I. These companies, for example, have required its process piping, process vessels and its pipe supports to be checked for signs of corrosion and for labeled photographs to be made when anomalies are found. Global estimated that this additional visual inspection work of the process equipment, piping and pipe supports requires an additional 2 to 4 hours for an average GOM production platform.

Galvotec thought this additional piping, process vessel and pipe support inspection work was as valuable, if not more valuable than the normal level I structural inspection work. Galvotec would recommend that operators have the Level I inspectors carry out this additional work and report any anomalies found. Galvotec said the additional inspection time would depend on the amount of equipment on the platform and the number of anomalies found. Some operators require all process equipment to be photographed and all photographs labeled, regardless of the equipments condition. This was reported to be very time consuming work and felt not necessary. These additional piping, process vessel and pipe support inspections carried out during Level I inspections often require a two-man crew.

Galvotec's normal level I inspections do not to include swing ropes, navigational aids, fog horns and other items normally covered under the Coast Guard's inspections.

3.3.5 Interview with Larry Bodin of Global X-Ray – May 27 2004:

Global X-Ray and Testing Corporation
P.O. Box 1536
112 E Service Rd
Morgan City, LA 70381
Larry Bodin (Engineering Manager)
lbodin@globalxray.com
Direct: 337-261-5840
Main: 1-800-264-2426
Fax: 1-985-631-0093
www.globalxray.com

The following is a recorded interview with Larry Bodin of Global X-Ray on this date:

Question: Are most of the investigations and surveys done by Global X-Ray considered routine or are they the result of a process failure?

Answer: About 95 percent of the Global X-Ray survey data is from scheduled or routine inspections and about 5 percent was from emergency inspections.

Question: Where on the vessels does Global X-Ray normally find most of the recorded leaks and corrosion?

Answer: The normal location for corrosion problems in horizontal pressure vessels, for example, is on the bottom of the vessel, near outlet nozzles in the weld HAZ. External corrosion is often a good indicator of potential internal corrosion problems in some vessels. The shell walls of pressure vessels usually show little sign of internal corrosion problems.

Question: Where should an inspector look first for signs of possible process system corrosion?

Answer: Look at the water handling equipment first. It is the best indication of possible corrosion problems in the rest of the process facility. If the water handling equipment is subject to corrosive elements, the water handling equipment will corrode much more rapidly and give an early indication of possible problems. Most corrosion problems with water handling equipment are found in the water skimmers and flotation cells.

Global X-Ray said if corrosion problems are found in the water handling equipment, then the next thing to inspect are the flowlines from the trees to the manifold center. If significant corrosion is found in both the water handling equipment and the flowlines, this was a good indication that there is also a high potential for internal corrosion in the rest of the process system. No significant corrosion found in the water handling equipment and the flowlines usually indicates there is not going to be significant corrosion found in the rest of the process system. Most of the GOM process equipment is not subject to high CO_2 or H_2S and therefore is not subject to significant internal corrosion. Global X-Ray says corrosion inhibitor injection is rarely needed in GOM process facilities.

When corrosion is found in the flowlines, the most common location is in the first few vertical and horizontal flowline joints and bends downstream of the choke. The turbulent high velocity flow after the chokes accelerates this area's corrosion. Global X-Ray says they believe the best inspection technique to be used for the flowlines is x-ray. Corrosion in the flowlines has been found to be much more rapid when the process fluid contains high CO_2 . H_2S is not a very frequent problem in the GOM.

HTHP Production:

Global X-Ray has not seen much high temperature / high-pressure production in the Gulf of Mexico. Global X-Ray says high pressure is not a problem since operators take pressure drops across chokes before the fluids enter the separators. However, Global X-Ray says some operators may not be reducing the pressures enough if the fluid is high temperature. A first stage separator and its flanges, for example, may be rated at 1440 psi at 130 degrees Fahrenheit operating temperature. If the process equipment is experiencing higher temperatures than what the system is rated for, the operating pressures should be lowered due to the high temperature, which is often not done. If the temperature in the first-aid separator is higher than 130 degrees Fahrenheit, the operator should de-rate the pressure vessel and lower the relief valve setting. For example, a 1440 psi / 130 degrees Fahrenheit operating temperature first stage separator, should probably be de-rated to 1200 psi if it is handing 175 degree fluids and the vessel's pressure relief valve setting should also be lowered to approximately 1375 psi.

Global X-Ray has not seen HTHP problems in the pipe work systems in the Gulf of Mexico except for possible flange rating reductions due to high temperature. The HTHP problem systems are usually associated with $C0_2$ components in the flow stream that create the corrosion problems.

Suggestions by Global X-Ray:

Oil companies should listen more closely to inspection company advice and suggestions with regard to what should be inspected and how that inspection should be done, especially if that inspection company's inspection personnel and engineers have many years of inspection experience.

For example: A client may only want to inspect horizontal pipe work sections. However, vertical pipe work sections have also been found to have problems in water treating system and flowlines. CO_2 in the well stream can cause corrosion to occur anywhere in the process pipe work and vessels.

Another example: An oil company may not require water handling equipment to been inspected because it is determined to be of low-risk to the company. However, if the water handling equipment fails, it will shut down the platform and that will have a very large financial consequence to the operator. Therefore, it is recommended that water handling equipment be a part of the facilities inspection program.

Operators normally do not have gas detectors in an open deck area. Global X-Ray has normally not found gas or oil leaks of any significance when they are doing their GOM facility inspections. Global X-Ray estimates that 1/4 to one-third of the operator's require their inspectors to carry a gas detectors with them prior to taking photographs or performing non-destructive testing.

Some operators leave very corroded or blistered pipe work, un-inspected and un-replaced for many years.

Global X-Ray maintains a web-based database that its customers can access for information on their facilities.

Conclusions from Global X-Ray Interview:

External visual inspection of process facilities can be a very good first indication of potential areas for further investigation. A trained visual inspector could inspect both the structure and the exterior of the process facilities. Having this information available to an oil company's personnel with statistics, trends and clearly summarized anomalies will allow the oil company to better understand its fleet, its problems and better organize its repair and maintenance.

Including the chemical content of all platform wells in this facility data base would allow inspectors to determine which wells have corrosive contents and the well pressures and temperatures. With this information, the inspectors could better focus their facility inspection time by risk ranking platform facilities and individual process facility components.

Conclusions from all interviews:

The view of the men interviewed was that process piping and process vessels should be included in the Level I inspections and anomalies photographed and reported on that pose significant safety or pollution risk. It is further recommended that personnel safety item anomalies such as: swing ropes, ladders, strength of walkways, strength of steps and condition of grating attachments should also be reported. If the reports from these additional surveys are limited to only significant anomalies, this additional inspection work should take only 1 or two hours on most GOM platforms.

It appears that the value and usefulness of Level I inspection reports could be improved by the inspector estimating the amount of needed repair by estimating:

- the area of grating,
- number of stair treads

- number of loose handrails
- surface area needing re-painting

This will help operators better plan for their needed platform repair and maintenance work.

A joint effort by the inspection companies and the operators could come up with an improved standard for Level I inspections that inspection companies could use as an evolving norm. There is a potential for an agreed standardization of: inspection methods, inspection recordings, sharing of records, permanent safe storage of records, reduction in duplication, etc.

Updates could be made as the industry and technology advances making these additional inspections and reports much less time consuming and more useful to the operators. For example, digital video recorders would allow inspectors to take digital pictures with a 6 second voice recording describing that picture. These pictures can permanently store the inspection results with linked voice recording notes and can easily be copied directly into the inspector's computer. These snapshots can easily be imported into reports as digital photographs and the voice recordings can serve as accurate notes describing the picture without the need to write down the notes. Hand held DVD recorders can store the images and voice recordings immediately to a DVD for each platform inspected or a whole series of platforms. Videos can also be made that record the overall condition of the platform and then focus in on a detail.

4. LIKELIHOOD OF DAMAGE / DEGRADATION

4.1 Topsides Structure

MSL has compiled a reliable, industry-wide database from the collective inspection data amassed by industry over the last ten years and beyond. The database includes data from the MMS, CAIRS, and multiple Gulf of Mexico platform operators. Details of over 3,000 underwater inspections have been catalogued and almost 5,000 anomalies recorded. An assessment of the underwater inspection has been carried out and has been separately reported [(48)].

The data relevant to topsides inspection was extracted and was carefully screened, manipulated, and reorganized into a more useful form for assessing the reported incidents. The original data were filtered and broken down into both anomaly type and structural component. During this process it was found necessary to divide existing categories further, such as corrosion into coating and corrosion. This distinction is useful since the coating of a component is first to deteriorate and should be reported as a separate incident to corrosion (metal loss), which takes place after the coating is depleted. After reviewing the revised data an apparent variance was establish from the original data.

Table 4.1 illustrates the anomalies reported during topside inspections of platforms in the Gulf of Mexico database and their percentage of the total 1,659 anomalies studied.

Component	*Corrosion*	*Coating*	*Dents/Bows*	*Impact*	*Separation/Missing*	*Other*	*Leak*	Total	Total %
Boat Landings	73	47	12	29	43	10		**214**	**12.90%**
Conductors	1				1			**2**	**0.12%**
Cranes	3				3	1		**7**	**0.42%**
Grating	90	19	21	4	39	7		**180**	**10.85%**
Handrails	183		53	2	130	54		**422**	**25.44%**
Helidecks	56	2	27	5	24	5		**119**	**7.17%**
Other	7				1	4		**12**	**0.72%**
Piping	6	3					3	**12**	**0.72%**
Platform CP	18					8		**26**	**1.57%**
Risers	34	3	10		3	11		**61**	**3.68%**
Riser CP	16	1			1	24		**42**	**2.53%**
Stairs	60	8	8	1	20	3		**100**	**6.03%**
Structures	77	36	36	1	57	10		**217**	**13.08%**
Swing Ropes	32				68	9		**109**	**6.57%**
Total	**656**	**119**	**167**	**42**	**390**	**146**	**3**	**1659**	**100.00%**
Total %	**39.54%**	**7.17%**	**10.07%**	**2.53%**	**23.51%**	**8.80%**	**0.18%**	**100.00%**	

Table 4.1: Reported Gulf Of Mexico Anomalies

The structural components and their relative anomalies are illustrated in Figure 4.1, Figure 4.2 and Figure 4.3. Handrails are responsible for about 25% of the reported anomalies and structures for approximately 13%. Of these anomalies the leading two attributors appear to be corrosion at about 40% and mechanical damage (separation/missing), about 23%.

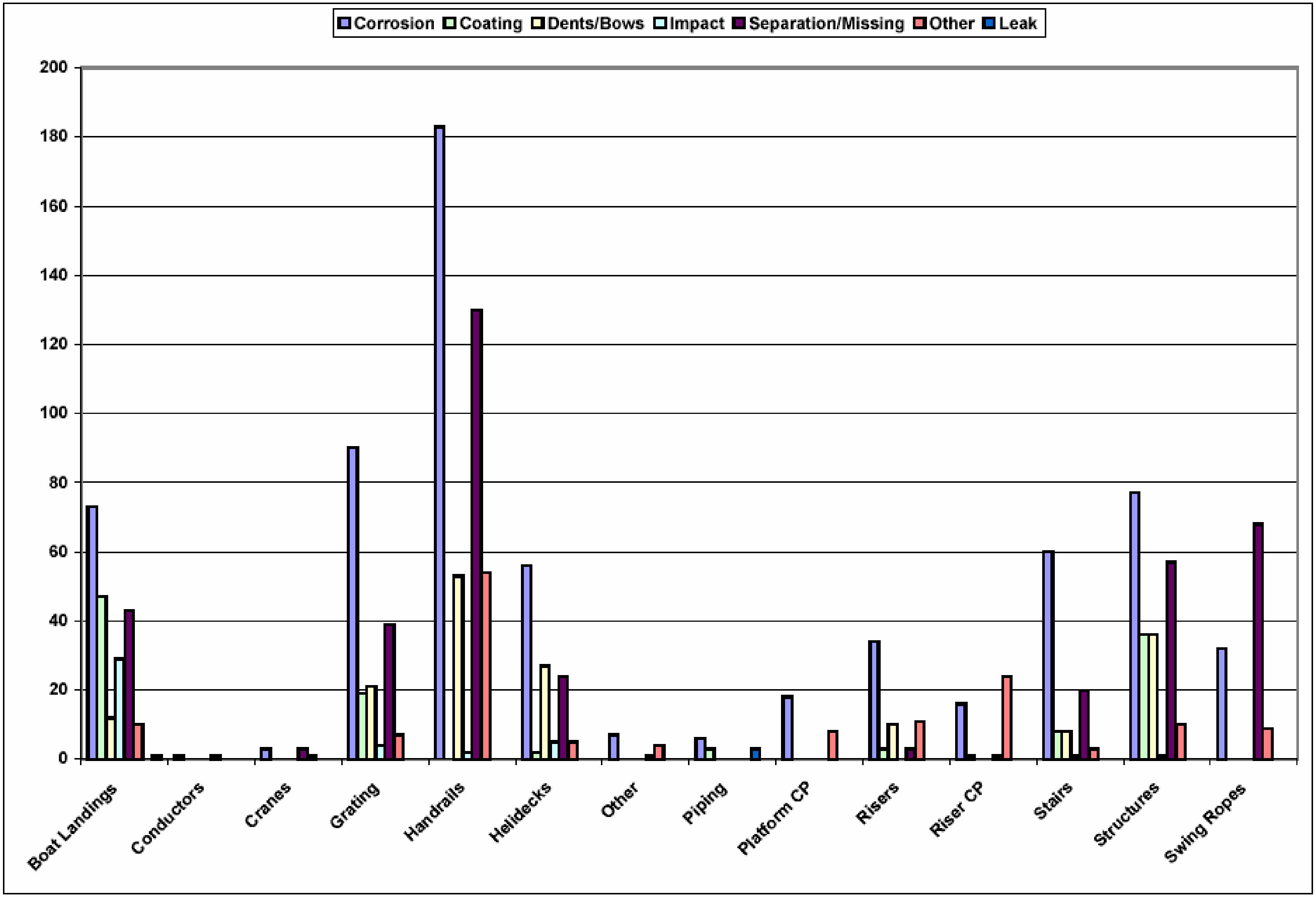


Figure 4.1: Distribution of Anomaly types and structural components

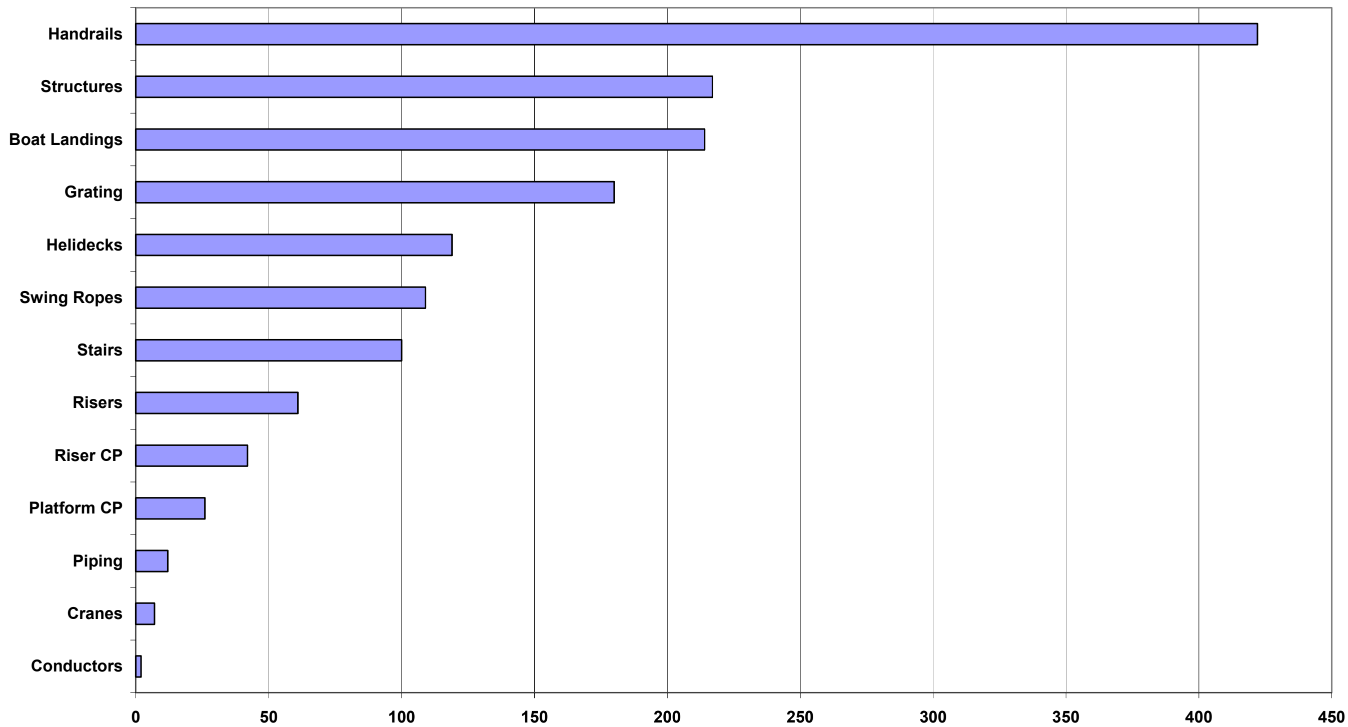


Figure 4.2: Total Anomalies by Structural Component

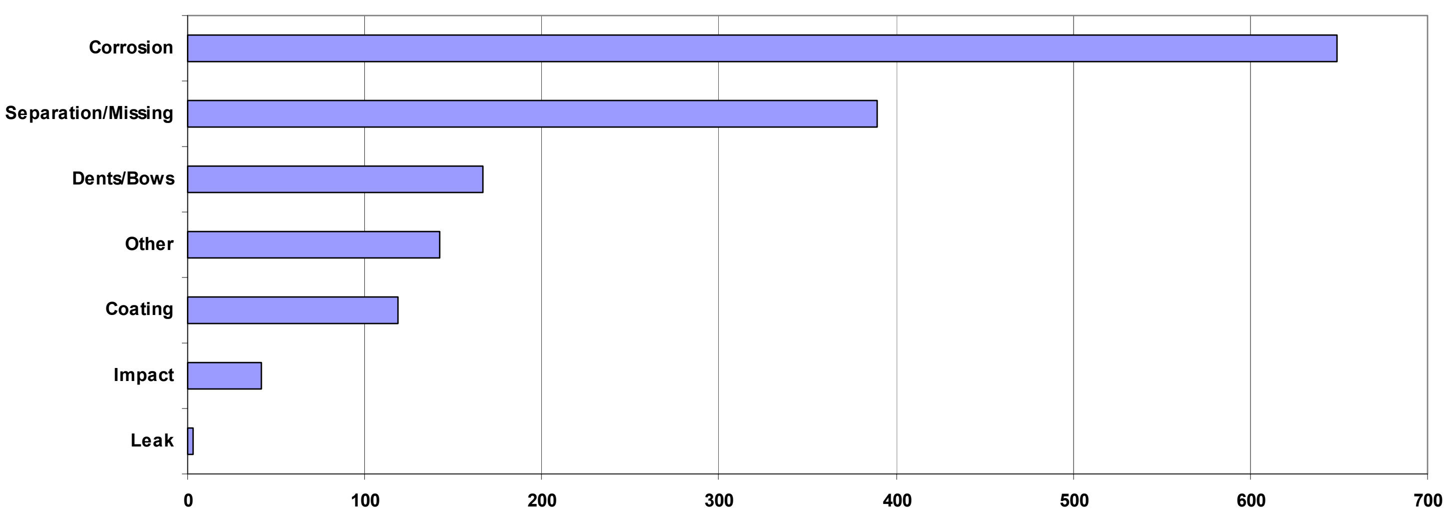


Figure 4.3: Total Anomalies by Anomaly Type

Of the structural components affected by the anomalies the following eight components were selected to investigate in further detail.

4.1.1 Handrails

Handrail anomalies include corrosion, coating, dents/bows, impact, separation/missing, and other. Figure 4.4 summarizes the extent and severity of handrail anomalies amongst the platform population in the Gulf of Mexico. The two primary causes of handrail anomalies are corrosion and separation/missing. Unexpectedly there is no coating damage reported while the majority of the reported anomalies are corrosion. This observation suggests that coating damage to the galvanized handrails is not of high concern to those surveying the platforms; it seems that only when the coating has decayed and metal loss ensues that the incident is recorded.

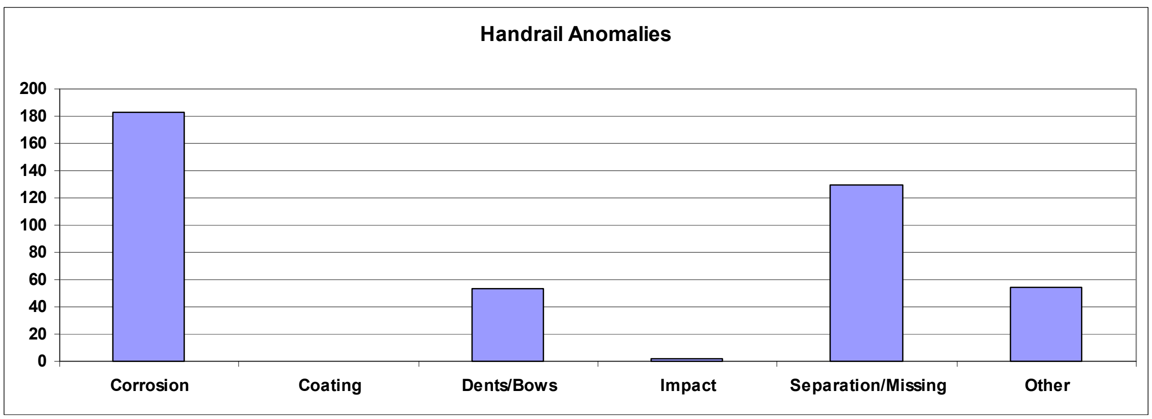


Figure 4.4: Gulf of Mexico Handrail Anomalies

4.1.2 Structures

Structure anomalies include corrosion, coating, dents/bows, impact, separation/missing, and other. Figure 4.5 summarizes the extent and severity of structure anomalies amongst the platform population in the Gulf of Mexico. The two primary causes of structure anomalies are corrosion and separation/missing. Unlike with handrails, coating appears to have been noted prior to leading to corrosion of the structure. Although the descriptions of the locations where corrosion has occurred are not always specific, it is possible to state that 17% of the corrosion anomalies relate to jacket locations, 29% to members, 27% to decks, and the remaining 27% to other or undefined locations. For deterioration of coating, the percentages are somewhat different, being 29% for jacket locations, 5% for members and 66% for decks. However, the coating anomalies are small in number and may not be identified as such where metal corrosion has actually occurred.

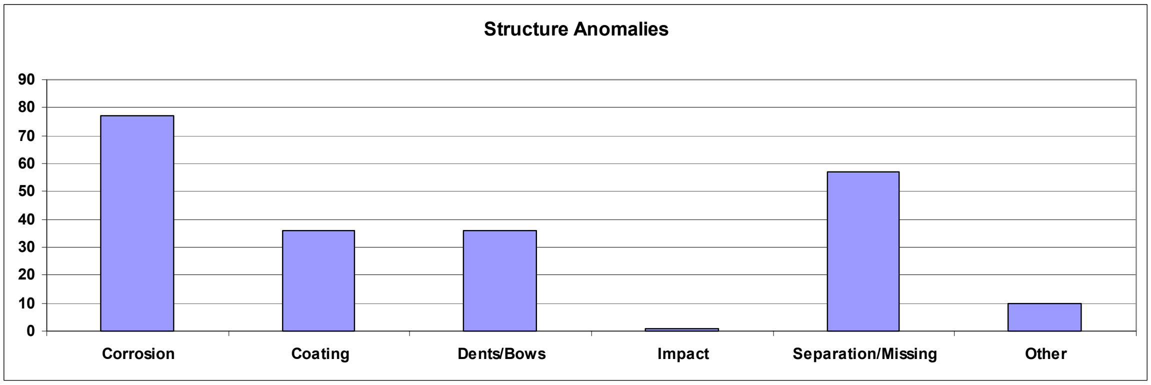


Figure 4.5: Gulf of Mexico Structure Anomalies

4.1.3 Boat Landings

Boat landing anomalies include corrosion, coating, dents/bows, impact, separation/missing, and other. Figure 4.6 summarizes the extent and severity of boat landing anomalies amongst the platform population in the Gulf of Mexico. The two primary causes of boat landing anomalies are corrosion and coating.

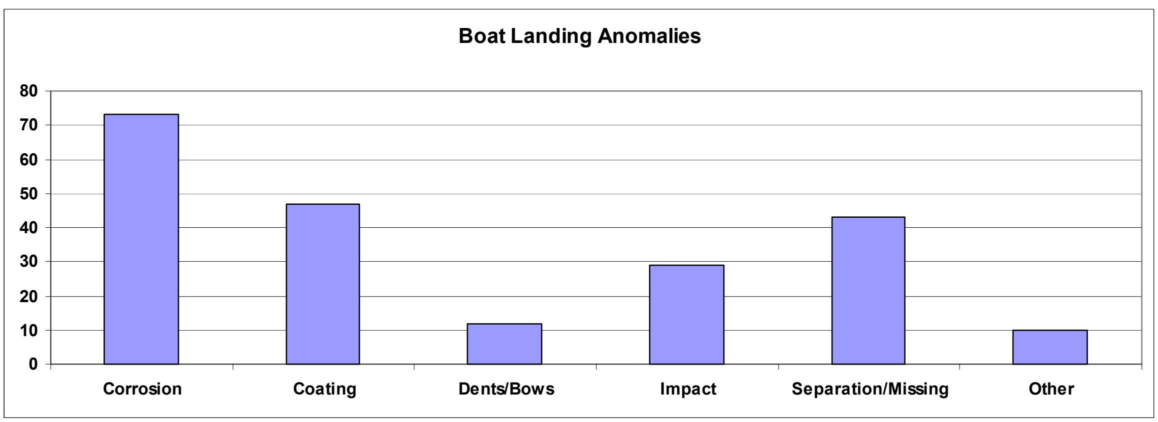


Figure 4.6: Gulf of Mexico Boat Landing Anomalies

4.1.4 Grating

Grating anomalies include corrosion, coating, dents/bows, impact, separation/missing, and other. Figure 4.7 summarizes the extent and severity of grating anomalies amongst the platform population in the Gulf of Mexico. The two primary causes of grating anomalies are corrosion and separation/missing.

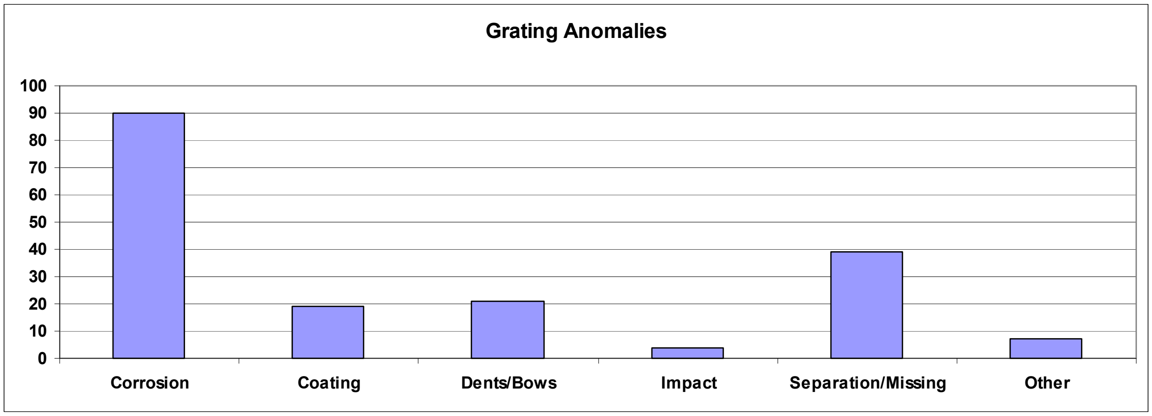


Figure 4.7: Grating Anomalies

4.1.5 Helidecks

Helideck anomalies include corrosion, coating, dents/bows, impact, separation/missing, and other. Figure 4.8 summarizes the extent and severity of helideck anomalies amongst the platform population in the Gulf of Mexico. The two primary causes of helideck anomalies are corrosion and dents/bows.

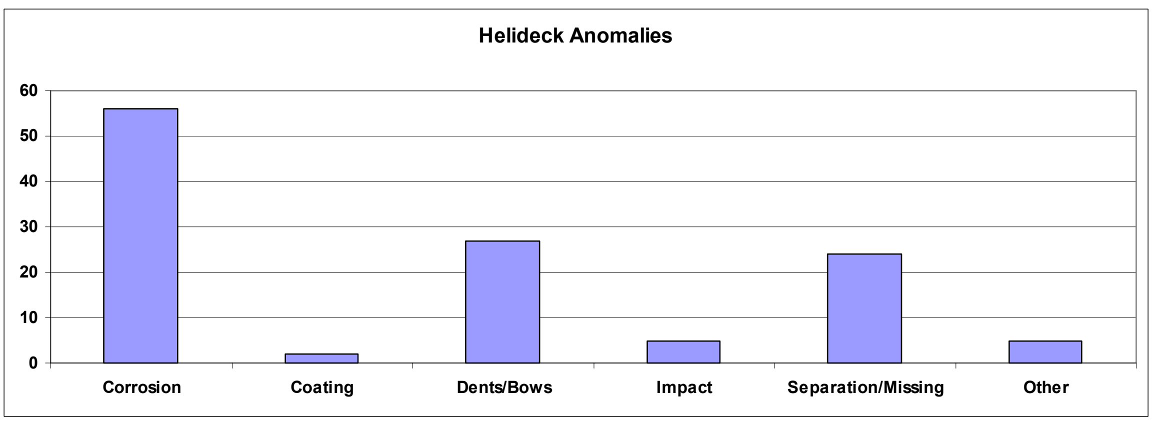


Figure 4.8: Gulf of Mexico Helideck Anomalies

4.1.6 Swing Ropes

Swing rope anomalies include corrosion, coating, dents/bows, impact, separation/missing, and other. Figure 4.9 summarizes the extent and severity of swing rope anomalies amongst the platform population in the Gulf of Mexico. The two primary causes of swing rope anomalies are corrosion and separation/missing.

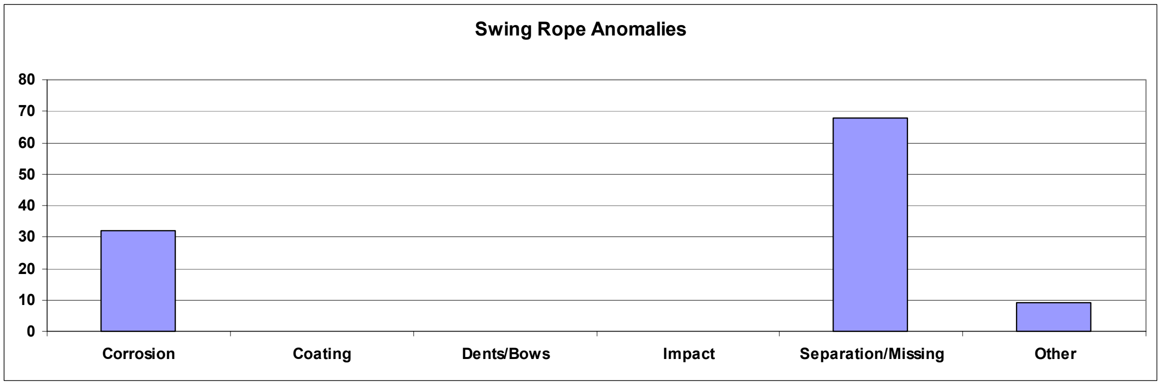


Figure 4.9: Gulf of Mexico Swing Rope Anomalies

4.1.7 Stairs

Stair anomalies include corrosion, coating, dents/bows, impact, separation/missing, and other. Figure 4.10 summarizes the extent and severity of stair anomalies amongst the platform population in the Gulf of Mexico. The two primary causes of stair anomalies are corrosion and separation/missing.

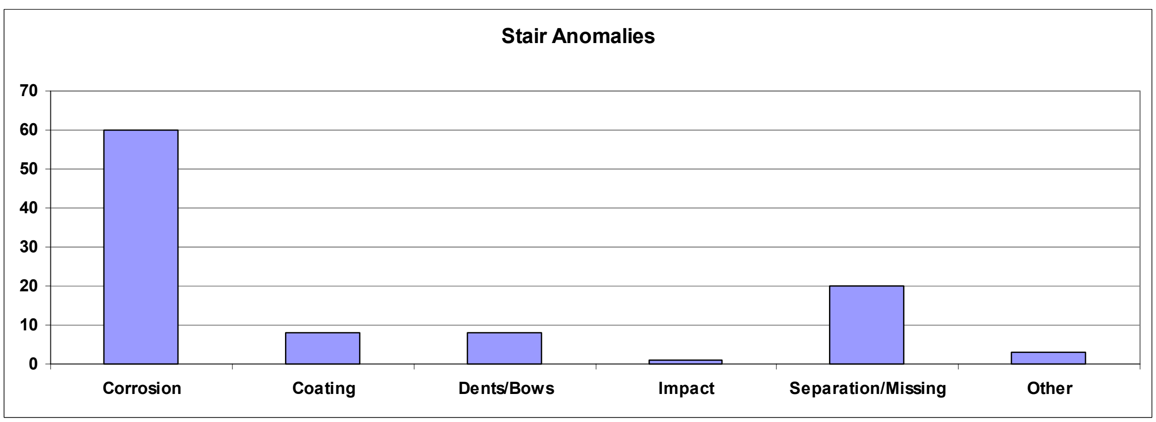


Figure 4.10: Gulf of Mexico Stair Anomalies

4.1.8 Risers

Riser anomalies include corrosion, coating, dents/bows, impact, separation/missing, and other. Figure 4.11 summarizes the extent and severity of riser anomalies amongst the platform population in the Gulf of Mexico. The two primary causes of riser anomalies are corrosion and other.

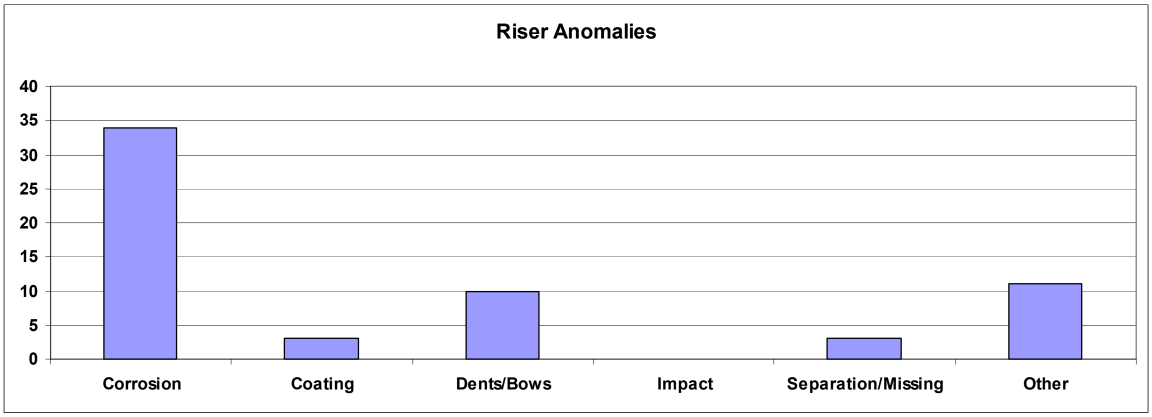


Figure 4.11: Gulf of Mexico Riser Anomalies

4.2 Operating Plant and Piping

Damage or degradation to operating plant and piping systems may arise from external sources (such as from dropped objects), machinery failure (usually the subject of reliability centered maintenance), or loss of containment in pressurized systems. This section is concerned with the last of these. The determination of anomaly and failure frequencies has been based where possible on the Global X-Ray database [46], but use has also been made of HSE data [44, 45].

Topsides process facilities can be categorized by system *or* by equipment type. This inevitably leads to a more involved analysis in comparison to topsides structures.

4.2.1 Systems Descriptions

The Global X-Ray data were initially analyzed to identify in which system each anomaly occurred. The NORSOK system coding [47] Annex A has been used for adding an appropriate system identifier. This has provided quite a detailed breakdown (some 31 separate systems under 5 main headings, each with a unique numeric identifier) as shown in Table 4.2.

Global X-Ray system category	No.	System description
Drilling, well and subsea related systems	13	Riser and well topside
Main process systems	20	Separation and stabilization
	21	Crude handling and metering
	23	Gas compression and re-injection
	24	Gas treatment
	25	Gas conditioning
	27	Gas export and metering
	28	Gas sweetening
	29	Water injection
Export and byproduct handling	30	Oil export line
	31	Condensate export line
	32	Gas export pipeline
	33	Oil storage
	36	Wellstream pipeline
	37	Gas injection / lift pipeline
	38	Glycol / methanol regeneration
Process support and utility systems	40	Cooling medium
	41	Heating medium
	42	Chemical injection
	43	Flare / vent
	44	Oily water
	45	Fuel gas
	50	Sea water
	53	Fresh water
	55	Steam
	56	Open drain
	57	Closed drain
	62	Diesel oil
	63	Compressed air
	64	Inert gas
Safety systems	71	Fire water

Table 4.2: Global X-Ray system descriptions

To allow comparison with HSE failure rate data [45], the following system groupings have also been used (Table 4.3).

HSE System description (failure rates)	No.	Global X-Ray system description
Separation, oil, production/ Separation, oil, test	20	Separation and stabilization
Metering oil	21	Crude handling and metering
Gas compression	23	Gas compression and re-injection
Processing, gas, dehydration	24	Gas treatment
Processing, gas, LPG condensate	25	Gas conditioning
Processing, gas, sour (H_2S/CO_2) treatment	28	Gas sweetening
Export oil	30	Oil export line
Export condensate	31	Condensate export line
Gas compression	32	Gas export pipeline
Processing, oil, oil treatment	33	Oil storage
Subsea well, gas injection	37	Gas injection / lift pipeline
Processing, oil, prod water treatment	44	Oily water
Utilities, gas, fuel gas	45	Fuel gas
Utilities, oil, diesel	62	Diesel oil

Table 4.3: HSE system descriptions (failure rates)

4.2.2 Equipment Types

The Global X-Ray data were further analyzed to identify which equipment type each anomaly occurred in. The NORSOK equipment type coding [47] Annex B has been used. This has provided a detailed breakdown of some 27 separate types under 13 main headings, as shown in Table 4.4.

Global X-Ray equipment category		Global X-Ray equipment description	
B	Drilling	BS	Choke/Production/Injection & Test Manifold
C	Miscellaneous Mechanical Equipment	CB	Non- Regenerative Filters
		CH	Chemical Feeders
F	Heaters, Boilers, Furnaces and Flares	FX	Other Heating, Burning and Boiling Equipment
H	Heat Transfer Equipment	HI	Reboilers/Evaporators
		HX	Other Heat Transfer Equipment
I	Instrumentation	IH	Oil Metering Packages
		IP	Pressure Instruments
K	Compressors, Blowers and Expanders	KX	Other compressors, blowers and expanders
L	Transfer and Control Equipment	LE	Pig Launchers/Pig Receivers
		LG	Production Risers
		LH	Injection Risers
P	Pumps	PX	Other Pumps
T	Storage Tanks / Containment Equipment – Atmospheric	TG	Sumps
		TX	Other Tanks
V	Vessels and Columns-Pressurized	VA	Separators
		VB	Contactors
		VD	Settling Drums, Knock-Out Drums and Flash Drums
		VG	Scrubbers
		VK	Dryers
		VL	Receiver and Surge Drums, Expansion-Head Tanks
		VW	Condensate Control Drums
		VX	Other Vessels and Columns
X	Miscellaneous Package Units	XE	Potable Water Pump Packages
L	Pipe	L	Pipe
C	Valves and special items function Codes	C	Check valve
		V	Manual valve

Table 4.4: Global X-Ray equipment descriptions

To provide a more manageable list of main equipment type headings, the 27 types have also been grouped according to the categories given in Cl.6.3.5 of API RP 580 (41) reproduced in Table 4.5.

API		Global X-Ray equipment descriptions	
a.	Piping	BS	Choke/Production/Injection & Test Manifold
		IH	Oil Metering Packages
		L	Pipe
		LG	Production Risers
		LH	Injection Risers
b.	Pressure vessels	CB	Non- Regenerative Filters
		CH	Chemical Feeders
		LE	Pig Launchers/Pig Receivers
		VA	Separators
		VB	Contactors
		VD	Settling Drums, Knock-Out Drums and Flash Drums
		VG	Scrubbers
		VK	Dryers
		VL	Receiver and Surge Drums, Expansion-Head Tanks
		VW	Condensate Control Drums
		VX	Other Vessels and Columns
d.	Heat exchangers	HI	Reboilers/Evaporators
		HX	Other Heat Transfer Equipment
e.	Furnaces	FX	Other Heating, Burning and Boiling Equipment
f.	Tanks	TG	Sumps
		TX	Other Tanks
g.	Pumps	PX	Other Pumps
		XE	Potable Water Pump Packages
h.	Compressors (pressure boundary)	KX	Other compressors, blowers and expanders
i.	Pressure relief devices	IP	Pressure Instruments
j.	Control valves (Pressure boundary)	C	Check valve
		V	Manual valve

Table 4.5: API RP 580 equipment type numbering

4.2.3 Anomalies

Recorded defects or anomalies are categorized by their severity, cause and location.

Severity

The Global X-Ray data ranks the severity by priority (refer to item (5) PRIORITY in Section 3.2 above) and in the following charts, the anomalies are divided between "FAILURE" and "PRIORITY 1-3".

Cause

Anomaly causes are categorized by Global X-Ray into five groups, as detailed in item (11) CAUSE in Section 3.2 above.

Faulty Installation
Internal Corrosion
Internal Erosion
External Corrosion
Weld Defect

Location

Anomaly locations are categorized by inspection of the Global X-Ray data, for comparison with HSE data [44], as follows:

1. Pipework
2. Valve
3. Flange/Joint
4. Instrument tapping pipework/fitting
5. Pumps, compressors and fans
6. Vessels and tanks
7. Heat exchangers
8. Fired heaters

4.2.4 Global X-Ray database benchmarking

The anomalies database received from Global X-Ray consist of 1,960 line entries. Of these, 1,937 entries contain adequate information for assigning equipment and system descriptions as classified above. The anomaly occurrence versus equipment and system category is shown in the following matrix (Table 4.6). The database contains a number of duplicate entries (with differing priorities) and these are discounted, the highest priority or failure being retained. After this filtering, the sample size reduces to 1,577 entries.

It is important to understand that the database is from a single inspection company, albeit from a wide variety of Gulf of Mexico operators. For reasons of confidentiality, it is not known which platforms were visited, nor therefore how representative the anomaly database is of the Gulf of Mexico as a whole.

It is also important to understand that the anomaly probabilities generated from the database are a simple count of the failures versus total defects recorded. They have not been normalized with reference to the number of systems or equipment items in operation.

Equipment Type	Riser and well topside 13	Separation and stabilisation 20	Crude handling and metering 21	Gas compression and re-injection 23	Gas treatment 24	Gas conditioning 25	Gas export and metering 27	Gas sweetening 28	Water injection 29	Oil export line 30	Condensate export line 31	Gas export pipeline 32	Oil storage 33	Wellstream pipeline 36	Gas injection / lift pipeline 37	Glycol / methanol regeneration 38	Cooling medium 40	Heating medium 41	Chemical injection 42	Flare / vent 43	Oily water 44	Fuel gas 45	Sea water 50	Fresh water 53	Steam 55	Open drain 56	Closed drain 57	Diesel oil 62	Compressed air 63	Inert gas 64	Fire water 71	Total
BS Choke/Production/Injection & Test Manifold	8	1																			2											11
IH Oil Metering Packages			1																													1
LG Production Risers	16									13		20																				49
LH Injection Risers															1																	1
L Pipe	462	299	4	10	3	20	2		9	66	4	81	10	3	43	5	2	2	7	48	165	67	2	16	1	60	35	2	2	2	2	1434
CB Non- Regenerative Filters																						14								2		16
CH Chemical Feeders																			10													10
LE Pig Launchers/Pig Receivers										2		1															1					4
VA Separators		88				3															35	2										128
VB Contactors					6																											6
VD Settling Drums, Knock-Out Drums and Flash Drums																						3										3
VG Scrubbers		6		5	1	11														27	2	28					1			4		85
VK Dryers																						1										1
VL Receiver and Surge Drums, Expansion-Head Tanks																		1											7			8
VW Condensate Control Drums						2																										2
VX Other Vessels and Columns													1				1			4		2		1								9
HI Reboilers/Evaporators																17																17
HX Other Heat Transfer Equipment																1	1	1														3
FX Other Heating, Burning and Boiling Equipment																		1														1
TG Sumps																										19						19
TX Other Tanks	2					2										1						1		6		1		1				14
PX Other Pumps																								1								1
XE Potable Water Pump Packages																								1								1
KX Other compressors, blowers and expanders				1																		1										2
IP Pressure Instruments	2	1			1	7	1	2		1						1					1	4	1						3	1		35
C Check valve	1		3								1								4							1						1
V Manual valve	42	6				1	1			3		6								1	8					3	4					75
																																1937

Table 4.6: Equipment vs. System chart for all Global X-ray Gulf of Mexico data

Thus the system failure statistics derived from the database cannot represent the relative safety of an individual system but should represent the relative numbers of that system type failing in the Gulf of Mexico as a whole. This is shown in the following two figures. Figure 4.12 shows system failure rates derived from HSE data [45], for the 15 systems with the highest failure probability. Gas compression has the highest rate per system.

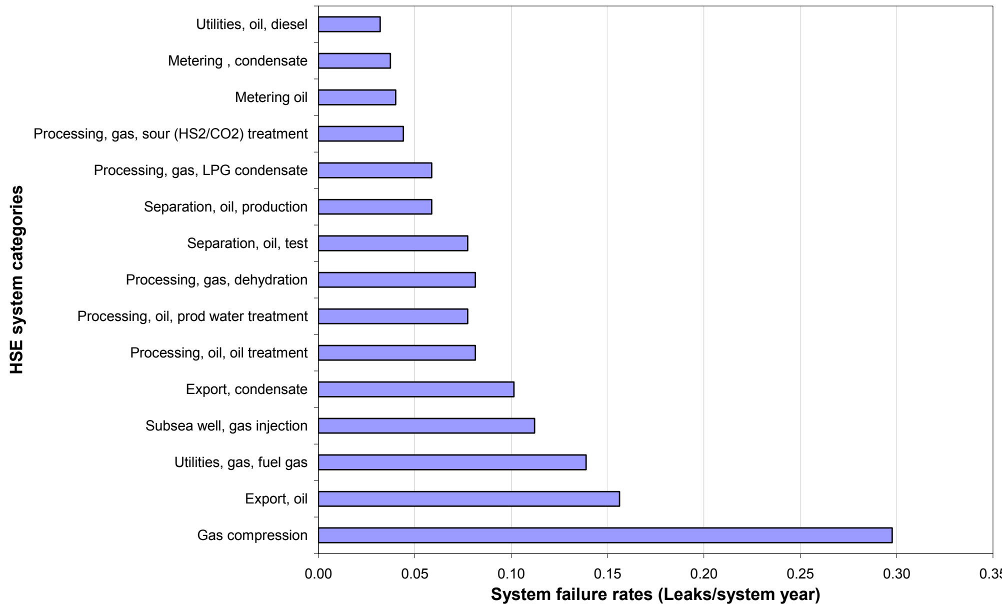


Figure 4.12: System failure rates (Leaks/system year) (HSE Data)

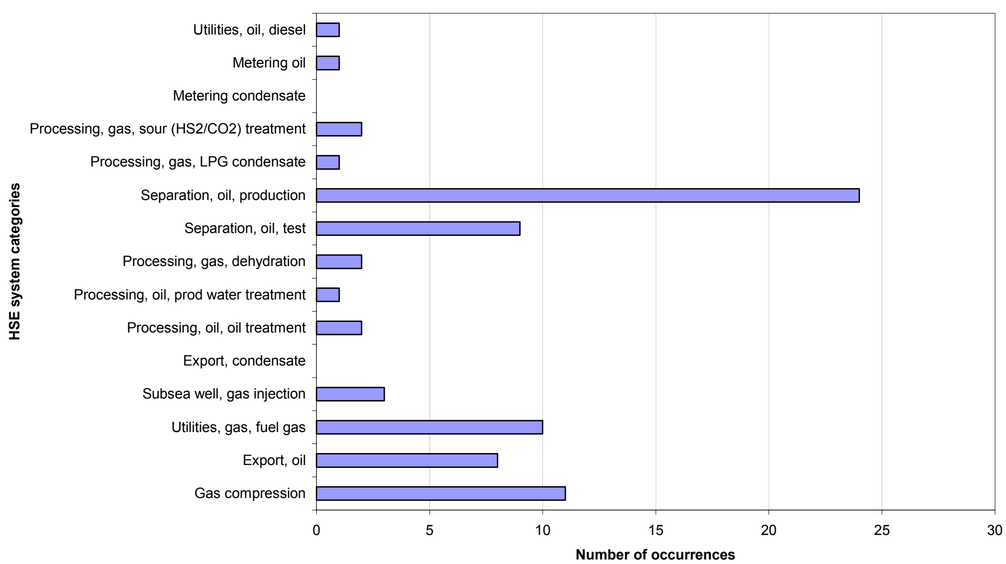


Figure 4.13: System failure (Number of occurrences) (Global X-Ray Gulf of Mexico Data)

Figure 4.13 shows the equivalent occurrence of failures in the Global X-Ray database. It can be seen that the number of gas compression system failures is significantly lower than oil separation systems, reflecting the size of their relative populations in the sample database, and arguably in the Gulf of Mexico as a whole.

The Global X-Ray data has been benchmarked against HSE corrosion/erosion data [44], as shown below (Figure 4.14). Both sets of data are based on actual failure incidents. The occurrences are remarkably similar, except for a significantly higher incidence of failures in the HSE export and import systems, compared with the Global X-Ray data (Figure 4.15). Conversely, the latter data displays a higher proportion of failures in the processing plant systems.

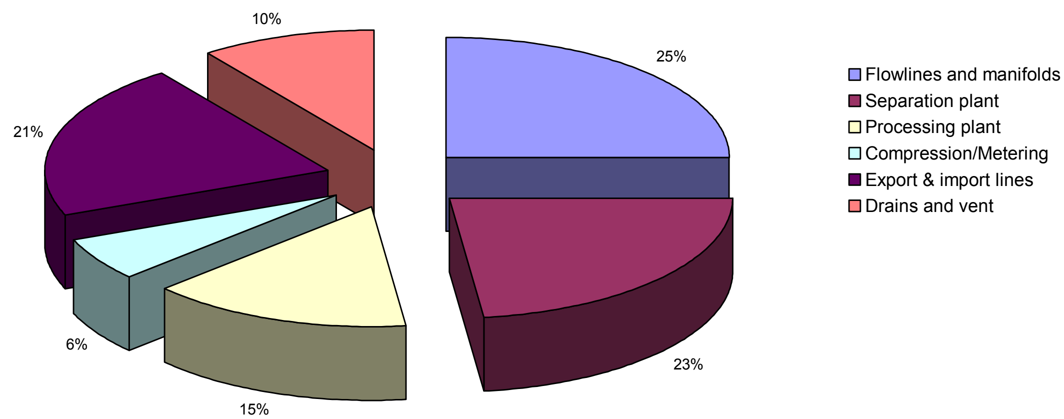


Figure 4.14: System vs. number of corrosion/erosion failures (HSE data)

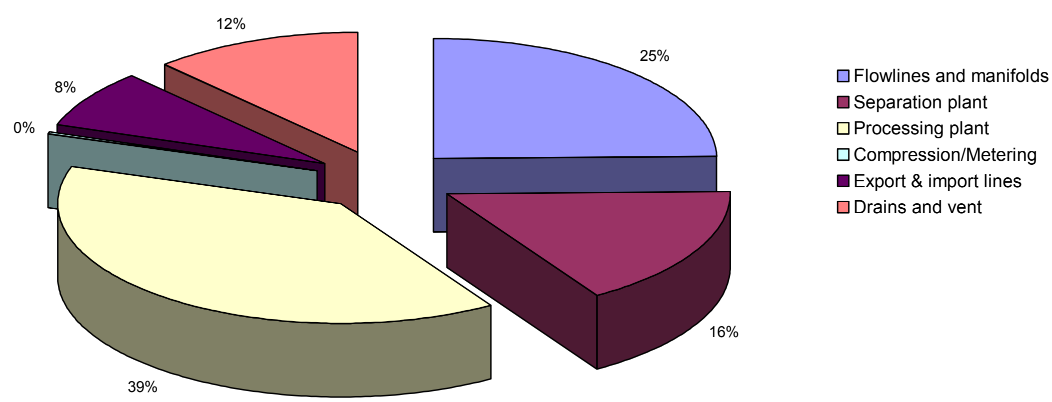


Figure 4.15: System vs. number of corrosion/erosion failures (Global X-Ray GOM Data)

4.2.5 Global X-Ray data analysis

The total number of anomalies has been determined for each main system category as shown in Figure 4.16.

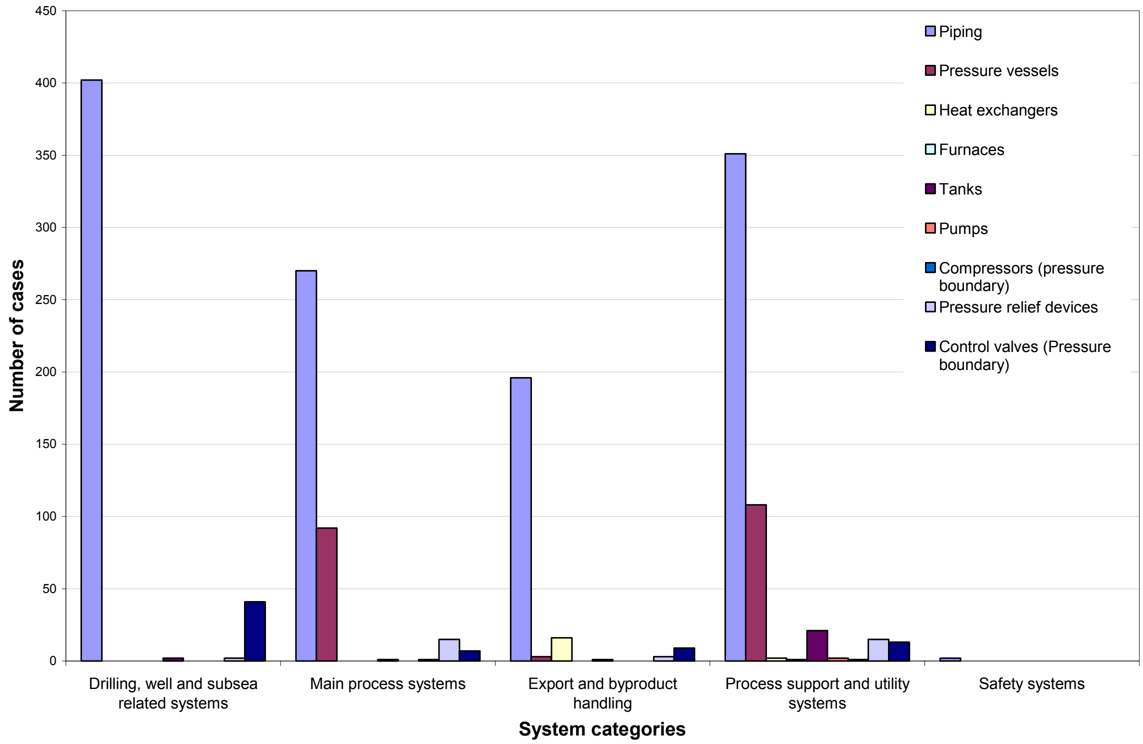


Figure 4.16: System vs. anomalies (Global X-Ray GOM Data)

It can be seen that the Drilling and Process Support system groups incur the greatest defect counts with a significant number also recorded in the Main Process systems.

Also immediately apparent is that the vast majority of anomalies are found in Piping (as an equipment "type") with Pressure Vessels coming "a poor second". This is starkly shown in Figure 4.17, and must reflect predominantly the extent of these on a platform relative to other equipment types.

At first, it was proving difficult to analyze the data since no background information is available on the sample population, such as the number of platforms, number of thickness measurement locations (TML), or access to P&IDs (see (2) CIRCUIT ID above). It was then decided to plot the number of **Failures** per system group compared with the number of detected anomalies *not* resulting in failure (**Priority 1-3**) to see if this would demonstrate any meaningful trend. The results are shown in Figure 4.18.

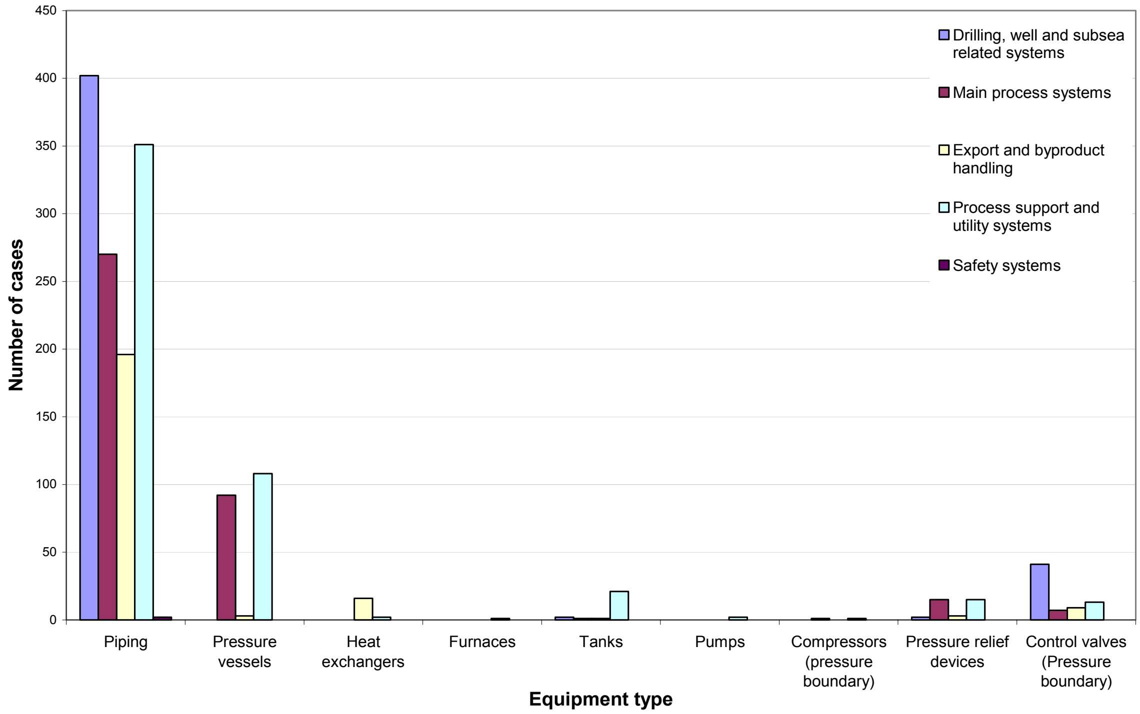


Figure 4.17: Equipment type vs. anomalies

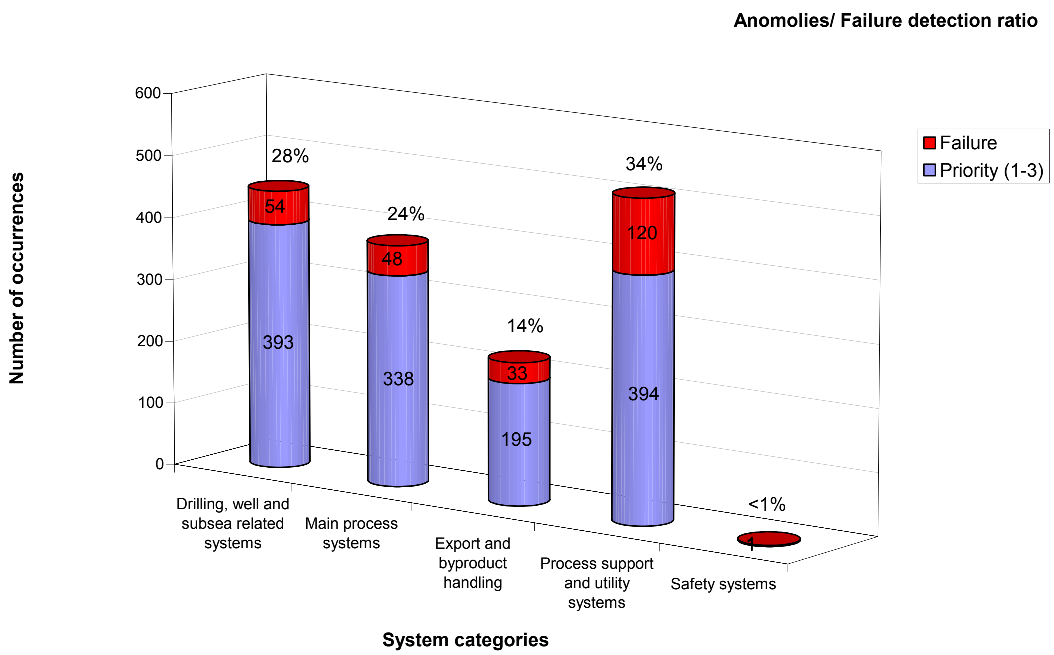


Figure 4.18: Anomalies/Failure detection rate

It is apparent that the number of failures occurring is not consistently proportional to the number of anomalies detected. The failure rate in the Process Support system group is more than twice the Drilling rate. This would indicate that the level of inspection for process support systems could beneficially be increased, with the intention of capturing defects before they result in failure.

4.2.6 Failure Causes - Systems

The cause of failure has been examined by system type, as shown in Figure 4.19 onwards. It can be seen that in the wellhead area, the primary cause of failure is internal corrosion, followed by internal erosion.

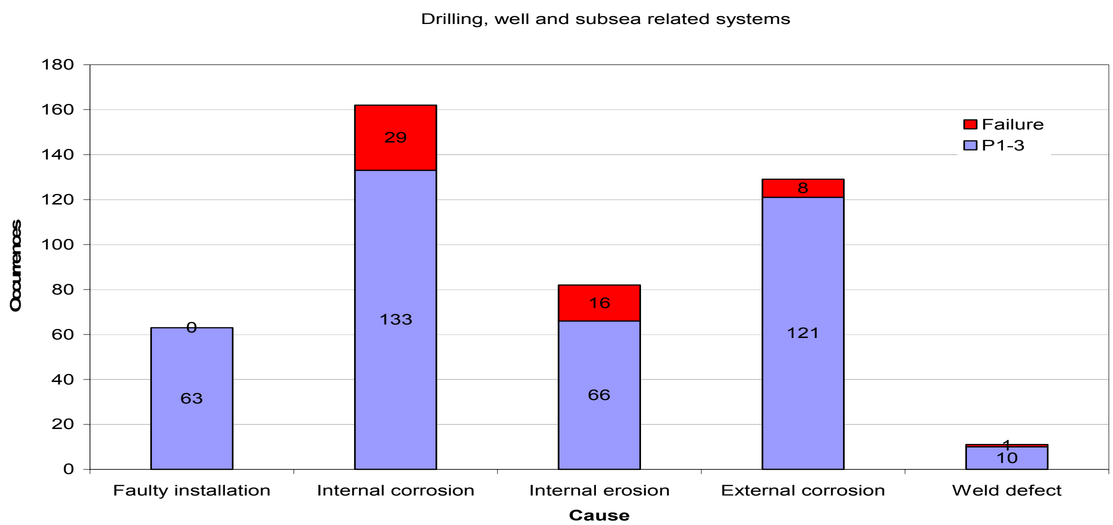


Figure 4.19: Cause of failure – Drilling, well and subsea related systems

In the main process area (Figure 4.20), internal corrosion is still the main issue in terms of failures but significantly more anomalies *not* resulting in failure are recorded under external corrosion. This may show that insufficient attention is being paid to internal corrosion, that the "gestation period" for internal corrosion is shorter than external corrosion, or simply that internal corrosion detection (by UT) also involves an external assessment but not *vice versa*.

The same characteristics are observed in the export and process support systems (Figure 4.21 and Figure 4.22 respectively). It is also apparent that the influence of internal erosion reduces the further downstream one looks, which accords with expectations: erosion being associated with well particulates and the higher fluid velocities encountered at the early stages of production.

The safety system anomalies are due to external (1 x failure) and internal (1 x priority1-3) corrosion but are statistically insignificant and therefore not shown.

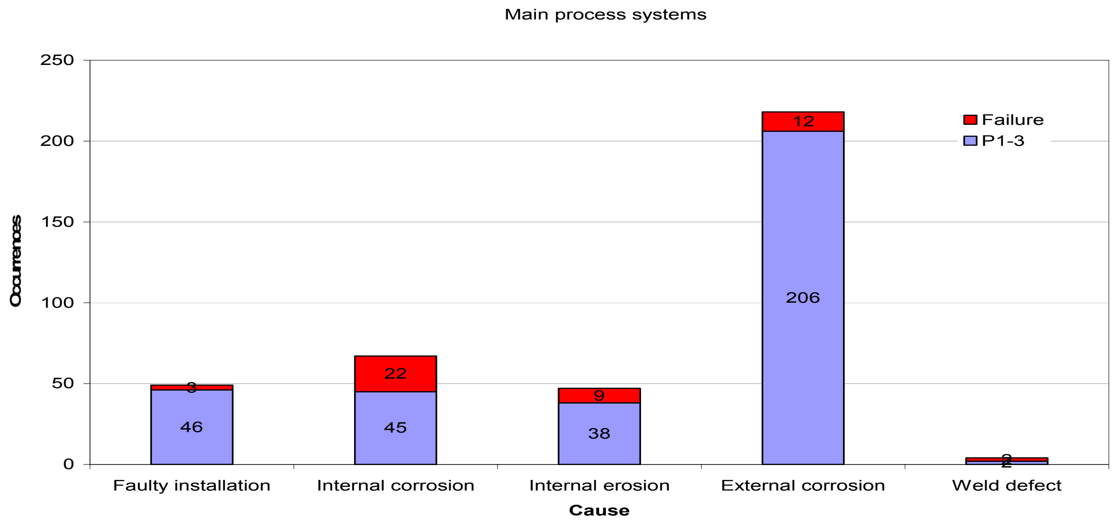


Figure 4.20: Cause of failure – Main process systems

It can also be seen that a number of anomalies are due to faulty installation but that these have not resulted in significant failure. This category typically includes incorrect PSV settings, underrated flanges and inadequate TOL thread engagement.

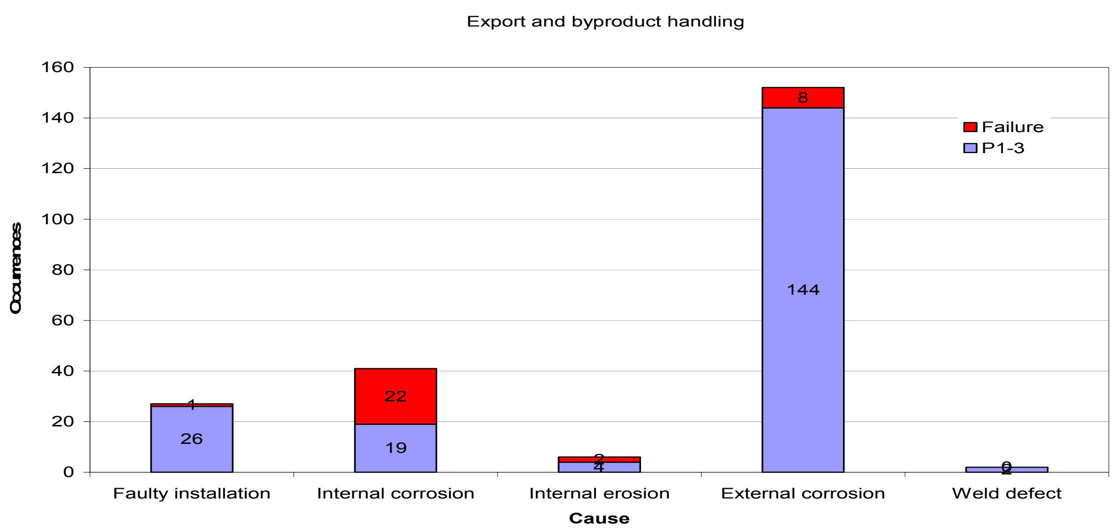


Figure 4.21: Cause of failure – Export and byproduct handling systems

Weld defects appear an insignificant cause of failure. It should be recognized, however, that this category relates purely to crack detection through X-ray examination. Anomalies arising through preferential corrosion or erosion at welds (or the HAZ) are typically recorded elsewhere, as appropriate.

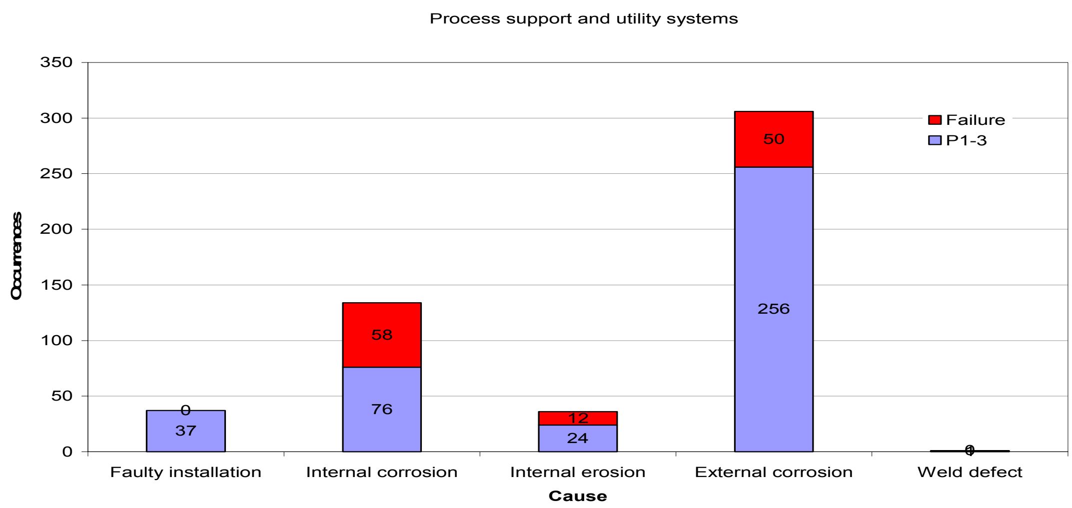


Figure 4.22: Cause of failure – Process support and utility systems

4.2.7 Failure Causes – Equipment

It is no surprise that piping, which makes up a major part of the process plant "equipment", follows a very similar pattern of defects as the main process and support systems (Figure 4.23). More corrosion anomalies are observed externally but more failures occur internally. Internal erosion is the third most important failure mechanism.

The distribution of defects in pressure vessels differs from piping in that erosion is generally not an issue, due presumably to the lower fluid velocities typically present (Figure 4.24). What is perhaps surprising is that 47% of internal corrosion anomalies give rise to failures, compared to just 2% of external corrosion defects. This implies that internal corrosion monitoring could beneficially be improved.

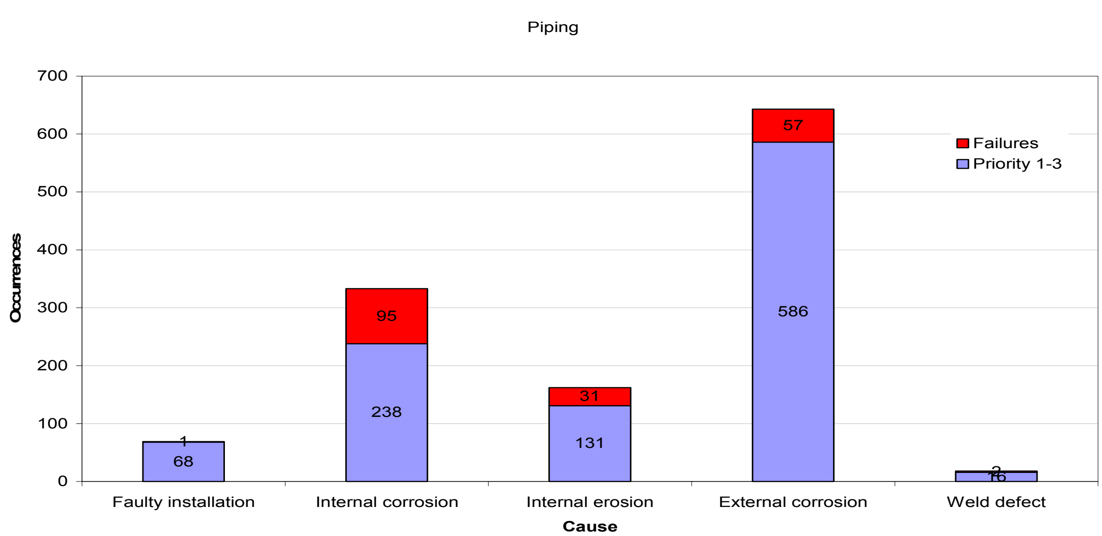


Figure 4.23: Cause of failure – Piping

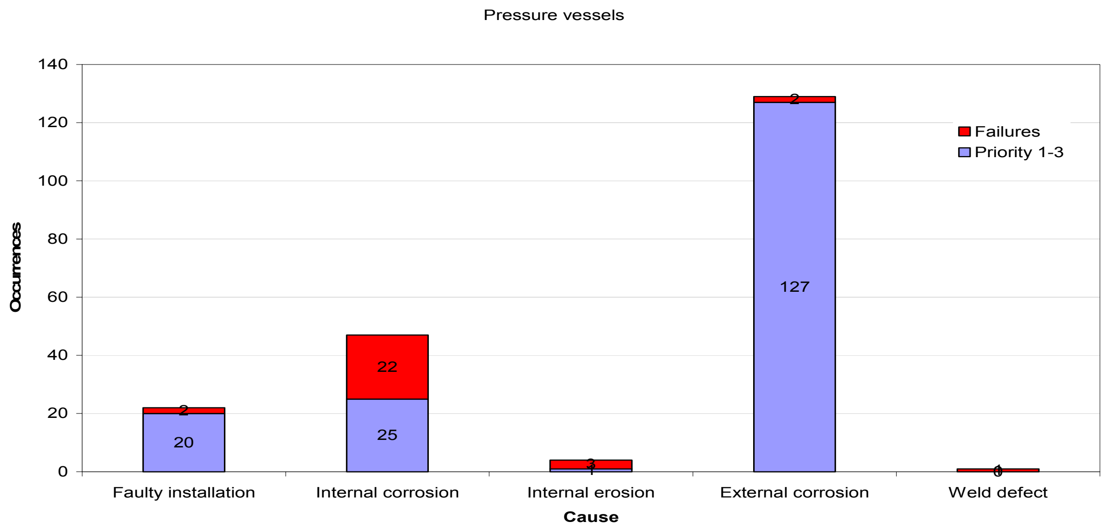


Figure 4.24: Cause of failure – Pressure vessels

As is readily discernable from Figure 4.17, defect frequency statistics for equipment other than piping and vessels are relatively scarce. However, it is perhaps a useful check on the data to see if the few anomalies recorded do tie in with expectations. Figure 4.25 gives the anomaly count for heat exchangers. As might be expected, internal corrosion is the main cause of failure.

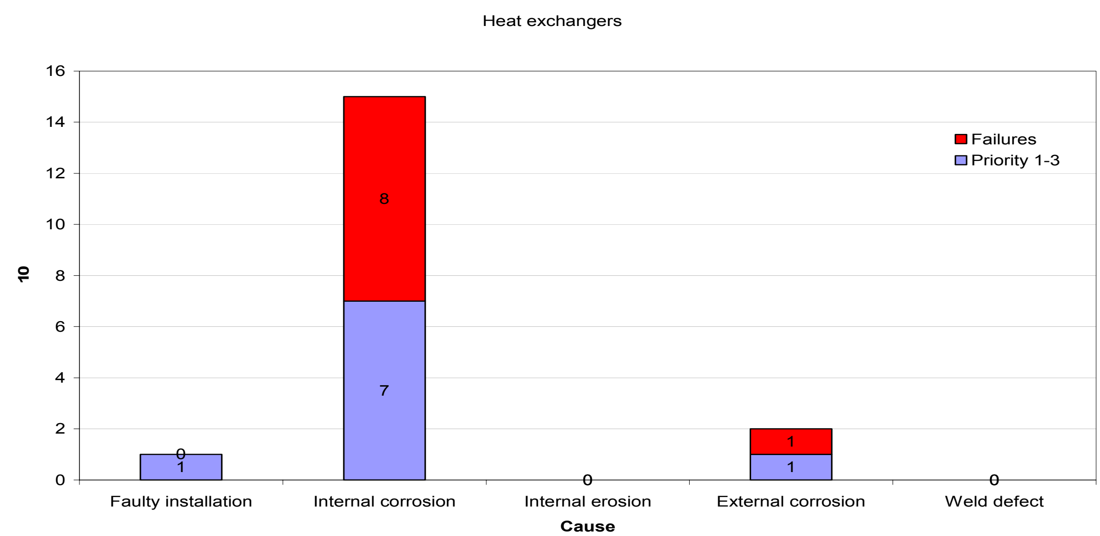


Figure 4.25: Cause of failure – Heat exchangers

By way of contrast, atmospheric tanks seem to fail equally from internal and external corrosion, although considerably more external corrosion defects as a whole are recorded (Figure 4.26).

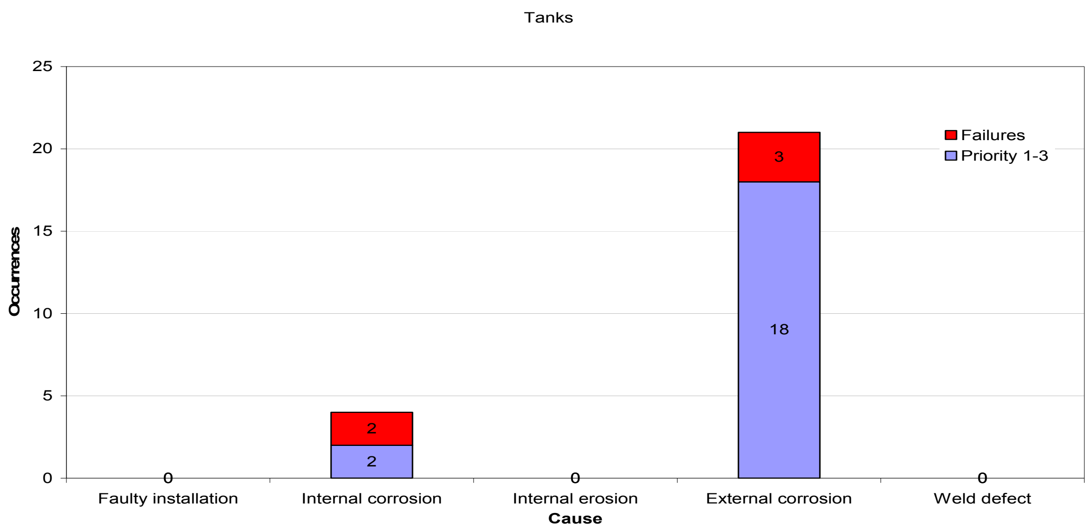


Figure 4.26: Cause of failure – Tanks

Of the remaining larger equipment items, there were 2 recorded compressor anomalies (external corrosion), 2 pump anomalies (one due to internal corrosion and the other to faulty installation), and 1 furnace anomaly (faulty installation).

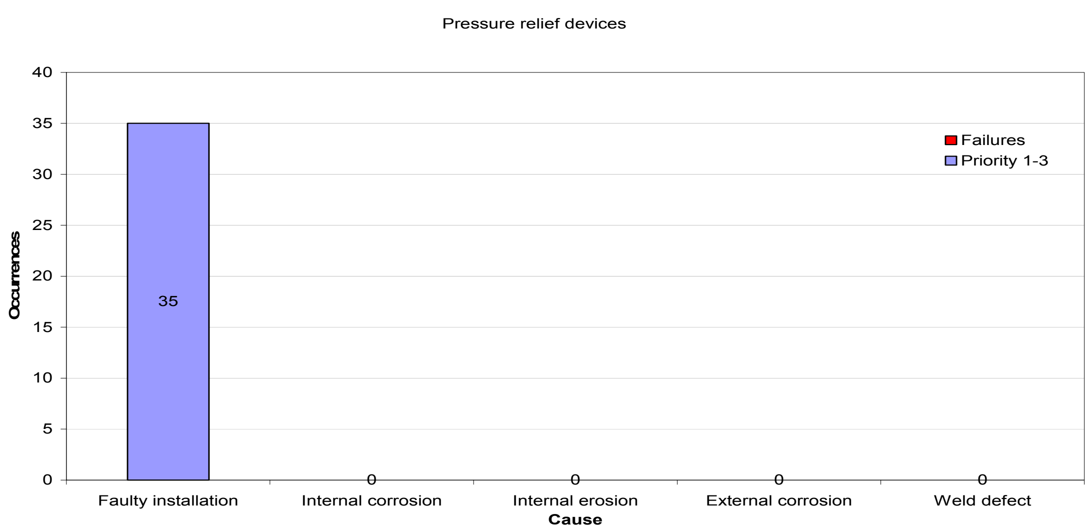


Figure 4.27: Cause of failure – Pressure relief devices

With regard to the control and shut down systems, the most number of defects recorded are due to faulty installation. There are no pressure relief device *failures* (Figure 4.27). Most reported anomalies are due to incorrect pressure setting.

"Control valves" has been interpreted broadly (Figure 4.28) and includes needle valves. Most of the faulty installation anomalies are lack of thread engagement. In contrast, most of the erosion/corrosion failures are leaks to main valve bodies.

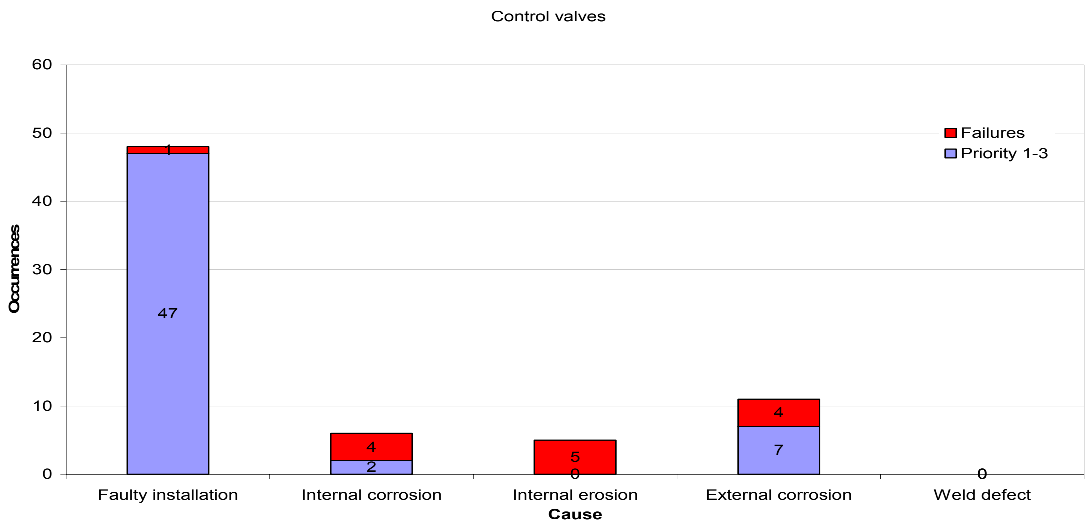


Figure 4.28: Cause of failure – Control valves

4.2.8 Failure Location

The location of leaks has been reviewed by the HSE [44]. The largest numbers of failures were more or less evenly distributed between pipework failures, valve loss of containment, flange/joint leaks and instrument tappings. Pumps, compressors, vessels, tanks and heat exchangers were much less likely to give cause for concern (Table 4.7).

	Pipework Failure	Valve Loss of Containment	Flange/Joint Leak or Failure	Instrument Tapping Pipework/Fitting	Pumps, Compressors and Fans	Vessels and Tanks	Heat exchangers	Fired Heaters	Total
Leaking gasket at gland or O ring	0	67	59	16	10	10	12	0	174
Corrosion, erosion or pinhole leak	123	16	3	10	1	3	7	8	171
In-service failure - no specific cause	30	7	7	26	9	1	4	5	89
Loose connection, bolting, plug or gland	1	22	37	20	4	2	2	0	88
Incorrect or deficient procedure or specification	9	3	23	13	2	3	0	0	53
Poor or deficient maintenance procedure	1	6	13	19	5	0	1	1	46
Vibration, fatigue or in-service stress	21	4	2	16	2	0	0	0	45
Seal failure	0	7	0	1	29	4	0	0	41
Other miscellaneous failure	1	20	0	10	1	2	1	0	35
Mechanical failure	0	3	1	1	27	2	0	0	34
Poor design or construction or manufacture	0	2	8	12	1	0	1	0	24
Total	186	157	153	144	91	27	28	14	800
%	23%	20%	19%	18%	11%	3%	4%	2%	100%

Table 4.7: Causes of incidents against location/type of equipment (HSE Data)

Of the corrosion/erosion/pinhole related incidents, some 72% occurred in pipework compared with 4% in vessels and tanks. This may be compared with the Global X-Ray data, where 66% was associated with pipework and 22% with vessels and tanks. From both sets of data, it is clear that piping failure is the major issue.

4.2.9 Other Failure Mechanisms

Loss of containment is just one of a number of topsides failure mechanisms that must be accommodated during the design and operation of an offshore platform. There are two other areas of particular importance. Firstly, the effective operation of the control, alarm, shutdown, and mitigation systems is essential to platform safety. Secondly, rotating machinery failure may, directly or indirectly, initiate hydrocarbon release.

A previous study [51] carried out on behalf of MMS examined fire and explosion incidents in the Gulf of Mexico. Figure 4.29 shows the distribution of causes of platform fires and explosions. The principal cause is from operation of rotating equipment, i.e. engines, compressors or turbines. The next major category involves platform welding operations. Other major causes are equipment and control component failures, electrical shorting, and poor operating procedures.

Despite the expectation that aging and therefore increased corrosion/erosion of the equipment and piping on a platform facility may be a major contributing factor to fires and explosions, no such dependency could be proven from the data. Several reasons were offered why this might be so. First, pressures and hydrocarbon throughput volumes of the platform facility will decline as the field gets older, thus lessening the potential for pressure leaks. Second, only the platform age was available in the database and this does not necessarily reflect the age of equipment and pipework, which may have been replaced due to obsolescence or because process conditions have changed which required refurbishment of the facility.

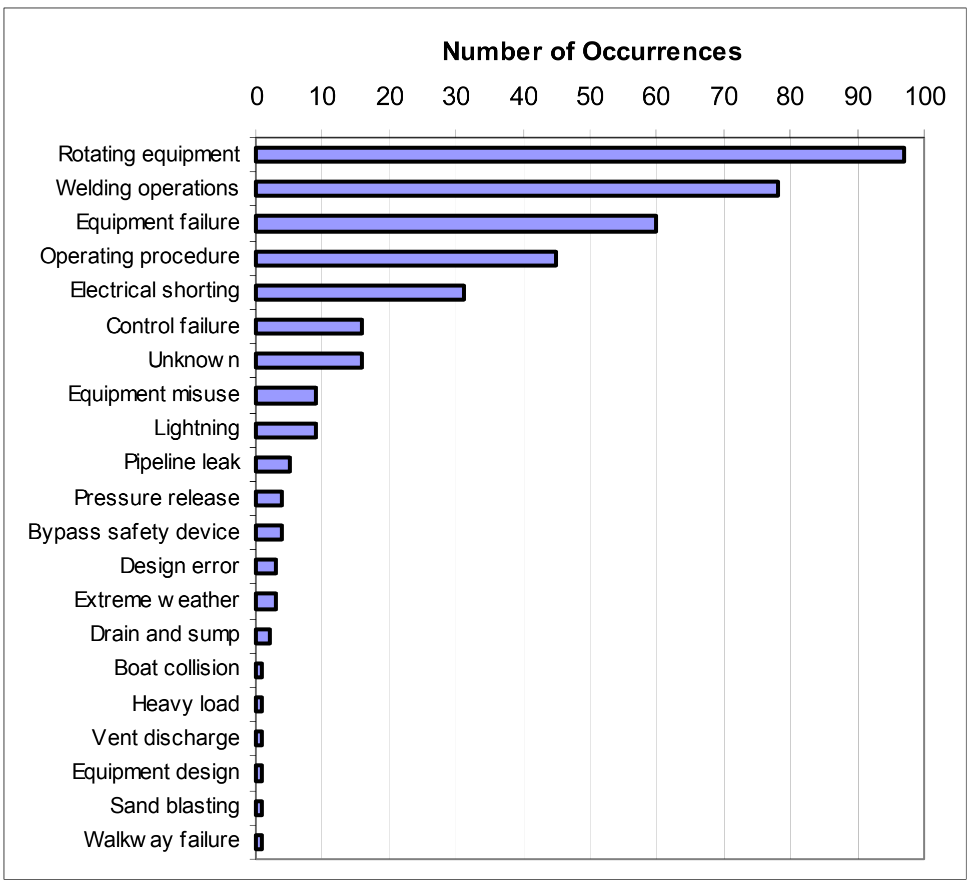


Figure 4.29: Distribution of fire and explosion causes

Accommodating these hazards efficiently requires determination of which systems are "safety critical" and then instituting appropriate inspection and maintenance regimes. An inspection program would typically follow the codes in Section 2.3 and might also be risk-based (2.3.6 Risk Based Inspection). It must also "mesh" with a preventive maintenance program, which would preferably be reliability-centered.

5. CONSEQUENCE OF DAMAGE / DEGRADATION

5.1 Introduction

Consequences of damage and degradation mechanisms can be regarded in terms of:

- Harm to personnel
- Harm to the environment, especially the fauna and flora
- Business disruption
- Reputation.

Each of the above categories is often graded according to the severity of the consequence. Different grades are used by various operators, both in the number of grades or sub-divisions defined and in the criteria used to differentiate between the grades. An example of one such grading system is provided in Table 5.1.

Section 1.7 of API RP2A [3] offers a categorization system based on life-safety and consequence of failure. The categories for life-safety and failure consequence, as defined in API RP2A Sections 1.7.1 and 1.7.2 respectively, are summarized in *Environmental consequence is labeled ‘Consequence of Failure’ in the API RP 2A.

Table 5.2. However, according to Section 1.7, additional factors should also be considered in determining the consequence of failure level, including: anticipated losses to the owner (repair/replacement of equipment or platform, lost production, cleanup), anticipated losses to other operators (lost production through trunklines), and anticipated losses to industry and government. The level to be used for platform categorization is taken as the more onerous of the categories for life-safety and consequence of failure.

It may be noticed that API RP2A (*Environmental consequence is labeled ‘Consequence of Failure’ in the API RP 2A.
Table 5.2) is very much geared towards categorizing the whole platform, and is of limited use in categorizing individual components of that system. The following subsections attempt to categorize components.

Grading	Category			
	Safety	Environment	Business Impact	Reputation
I	Potential for 30+ fatalities	Long term damage to the eco-system, poor potential for recovery to normal state	Losses > $US 1 billion, and viability of future operations in the region	International media, forced to withdraw from region, public inquiry, general loss of confidence in company
II	Potential for 10 to 30 fatalities	Medium term damage to the eco-system, possible to recover within 10 years	Losses $US 100M to $US 1 billion	International media, regulatory intervention, corporate prosecution, punitive fines
III	Potential for 2 to 9 fatalities	Eco-system affected for up to 2 years with reasonable recovery potential	Losses $US 10M to $US 100M	Headlines in international media, ongoing coverage in national media, prosecution
IV	Potential for single fatality or serious injury	Localized short term change to eco-system, good recovery potential	Potential for minor cost or revenue impact	Headlines in national media, possible prosecution by regulator
V	Potential for first-aid / medical treatment / lost time injury	Localized short term effect on eco-system that is unlikely to be noticeable	Negligible cost or revenue impact	Mention in local media, queries by regulator

Table 5.1: Example of Consequence Categories

Life-Safety Consequence		**Environmental Consequence***	
Category	Description	Category	Description
L-1	*Manned-Nonevacuated* Platform continuously occupied, and evacuation prior to design environmental event is not intended or is not practical.	L-1	*High Consequence* Major platforms, or platforms having potential for well flow of oil/sour gas in event of platform failure. Also includes platforms supporting major oil transport lines and/or storage facilities.
L-2	*Manned-Evacuated* Platform normally manned except during forecasted design environmental event.	L-2	*Medium Consequence* Platforms where production would be shut-in by subsurface safety valves during the design event. Oil storage limited to process inventory and surge tanks.
L-3	*Unmanned* Platform not normally manned.	L-3	*Low Consequence* Minimal platforms standing in water depths no greater than 100 feet where production would be shut-in by subsurface safety valves during the design event. Typically refers to caissons and small well protectors.

*Environmental consequence is labeled ‘Consequence of Failure’ in the API RP 2A.

Table 5.2: Life-safety and consequence of failure categories to API RP2A

5.2 Structural items

Table 5.3 presents a list of topsides structural components and other items that are typically inspected during topside structural and coating surveys. Against each component or item, a comment of the possible consequence of failure is made. The third column in the table contains a component classification for the consequence of failure and is discussed below.

It can be seen that structural failure, should it occur, generally has the potential to lead to severe consequences, if not directly then by escalation. However, it should be noted that the consequences of failure are not only determined by the nature of the failure, but also by the circumstances under which the failure occurred. For example, a walkway grating perhaps weakened by corrosion may fail and be washed away in a severe storm, or fail as it is stepped upon. Clearly, the consequence of failure in the latter case is far more serious than the former.

The consequence of a particular component failing may also be a function of the overall platform exposure level as defined, for example, by the L-1, L-2 and L-3 levels in API RP2A and summarized in *Environmental consequence is labeled 'Consequence of Failure' in the API RP 2A.

Table 5.2 above. In other words, the platform exposure level may modify the consequence of failure of a particular component. For example, the failure of a pipe support on a L-3 platform has potentially a lower consequence as a similar failure on a L-1 platform. On the other hand, the failure of a walkway grating leads to similar consequences (potential fatality) on both L-1 and L-3 platforms.

Recognition has to be given to the varying conditions of platforms in the Gulf of Mexico, and elsewhere. Many platforms are in good condition, with little sign of deterioration of even coatings. Unfortunately, there are also too many in a poor state with advanced metal loss occurring. In order that any guidelines arising from this study can have the widest range of application, and therefore be the more useful, it is considered important that inspection prioritization takes due account of the condition of the existing infrastructure in a pragmatic manner. The key to this is to include platform exposure level into the methodology that categorizes the consequence of failure of a particular component.

Figure 5.1 presents the proposed consequence matrix for the components and items listed in Table 5.3. The two inputs into this matrix are the platform exposure level and the component failure consequence. The output is one of three consequence levels. The platform exposure levels are recommended to be those defined in API RP2A because they would appear to be entirely appropriate for the present purposes and because each installation should have been already categorized as either L-1, L-2 or L-3 by the operator. A summary of the platform exposure levels is presented in *Environmental consequence is labeled 'Consequence of Failure' in the API RP 2A.

Table 5.2 but, as noted in Section 5.1, other commercial considerations may also influence the selection of the platform exposure level; full details may be found in API RP2A.

Component / Item	Consequence of Failure	Class.
Primary structural framing	Large potential for loss of life and loss of inventory, particularly if there is no structural redundancy	A
Secondary & tertiary structural framing	Can lead to secondary consequences, if members are supporting heavy equipment or providing support to hydrocarbon piping/equipment	B
Leg/pile weld connection	Potential to lead to secondary consequences, especially if platform has 4 legs or less	B
Bridges & associated support structure / bearings	Potential for loss of life and loss of inventory. Non-functioning sliding bearings can impose additional loads to bridge structure leading to fatigue failure of structure	B
Boat landings & fenders	Potential for loss of life	D
Crane pedestals	Loss of operational capability	C
Derrick substructure & skid beams	Loss of operational capability	E
Flare/vent towers	Potential for tower collapse / Loss of venting capability	B
Communication towers	Potential for tower collapse	D
Deck plating/grating	Direct consequence for personnel safety	A
Helideck & safety nets	Direct consequence for personnel safety	A
Walkway grating & supporting structure/hangers	Direct consequence for personnel safety	A
Handrails incl. posts	Direct consequence for personnel safety	A
Stair treads & stair stringers	Direct consequence for personnel safety	B
Swing ropes	Direct consequence for personnel safety	A
Survival craft & divots	Direct consequence for personnel safety	B
Access platforms & attachment pts.	Direct consequence for personnel safety	A
Pipe racks	Potential for collapse of rack and falling pipes	C
Pipework supports	Potential for loss of inventory	B
Risers & supports	Potential for large loss of inventory	A
J-tubes & supports	Loss of operational capability	D
Conductors & supports	Loss of operational capability	D
Service caissons & supports	Loss of operational capability	D
u/w cathodic protection system	Permits degradation by corrosion	E
Coatings	Permits degradation by corrosion	Varies

Table 5.3: Consequence of failure - Structure

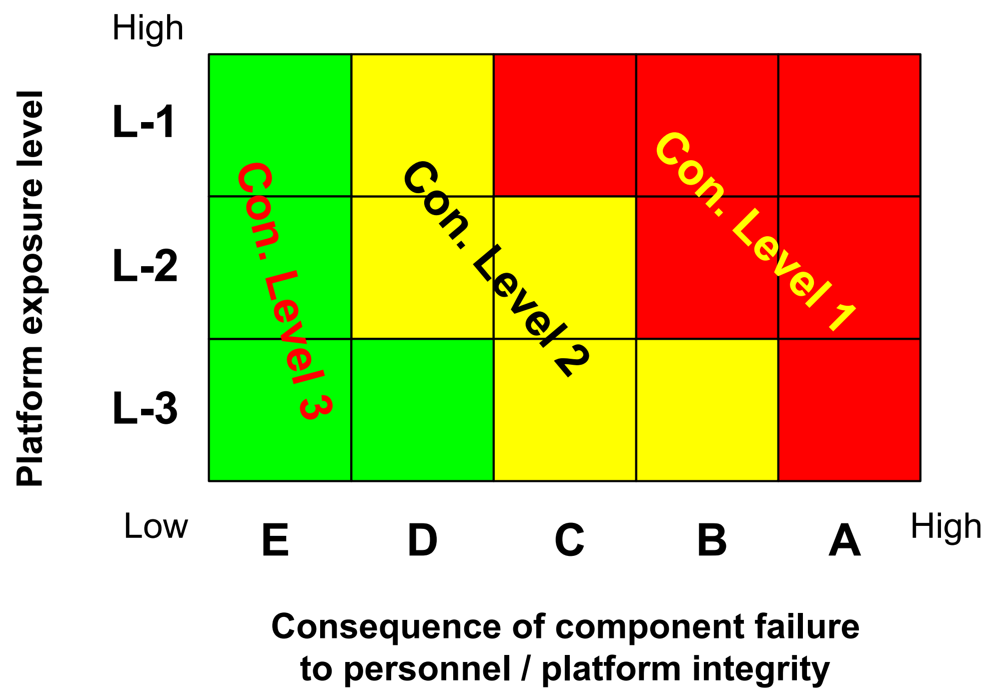


Figure 5.1: Matrix for defining "Consequence Levels"

The component failure consequence is intended to relate only to the specific platform itself including the personnel on the platform. That is, all platforms are considered to be of "equal value" for initially assessing the consequence of failure of a particular component. Five levels, designated A to E, are indicated in Figure 5.1. Suggested minimum levels are given in the final column of Table 5.3. These levels have been assigned on the basis of personnel safety and loss of hydrocarbon inventory but not on economic grounds.

Armed with the platform exposure level (L-1 to L-3) and the initial consequence of component failure (A to E), the matrix in Figure 5.1 outputs one of three final Consequence Levels (1 to 3). Inspection of Figure 5.1 reveals that all components initially assessed as being of consequence Level A, such as primary structure, gratings and swing ropes, remain at the highest Consequence Level 1, no matter what the platform exposure level is. A components initially assessed as Level B, such as secondary structural framing, are finally given the highest Consequence Level 1 for platform exposure levels L-1 and L-2, and the medium Consequence Level 2 if the platform exposure is L-3.

5.3 Operating Plant and Piping

The approach to categorizing failure consequence used in Section 5.2 above has also been adopted for the topsides facilities. The consequence class (A through E) has been determined on a system basis, taking into account five weighted parameters. Approximate ranges for these are given below:

Pressure:	0 = low	(0 – 100 psig)
	1 = medium	(100 – 1,000 psig)
	2 = high	(>1,000 psig)
Volume:	0 = batch inventory	
	1 = process inventory	
Temperature:	0 = low	(0 – 150 ºF)
	1 = high	(>150 ºF)
Fluid phase:	0 = liquid	
	1 = gas / mixed phase	
Hydrocarbon content:	0 = none	
	1 = contaminated	
	2 = hydrocarbon	

Consequence classes are assigned as follows:

Weighted Score	Class
6 – 7	A
4 – 5	B
3	C
2	D
0 – 1	E

The resulting system designations are shown in Table 5.4. It should be emphasized that the firewater class (E) represents the direct consequence of the system itself failing. The system, however, is safety critical because of its key role in mitigating other incidents.

No.	System description	P	V	T	F	H/C	Total	Class
13	Riser and well topside	2	1	1	1	2	7	A
20	Separation and stabilization	1	1	1	1	2	6	A
21	Crude handling and metering	1	1	1	0	2	5	B
23	Gas compression and re-injection	2	1	0	1	2	6	A
24	Gas treatment	1	1	0	1	2	5	B
25	Gas conditioning	1	1	0	1	2	5	B
27	Gas export and metering	2	1	0	1	2	6	A
28	Gas sweetening	1	1	0	1	2	5	B
29	Water injection	2	1	0	0	0	3	D
30	Oil export line	1	1	1	0	2	5	B
31	Condensate export line	1	1	0	1	2	5	B
32	Gas export pipeline	2	1	0	1	2	6	A
33	Oil storage	0	1	1	0	2	4	B
36	Wellstream pipeline	2	1	1	1	2	7	A
37	Gas injection / lift pipeline	2	1	0	1	2	6	A
38	Glycol / methanol regeneration	1	0	1	1	2	5	B
40	Cooling medium	1	0	0	0	0	1	E
41	Heating medium	1	0	1	0	0	2	D
42	Chemical injection	2	0	0	0	1	3	C
43	Flare / vent	2	1	1	1	2	7	A
44	Oily water	0	0	0	0	1	1	E
45	Fuel gas	1	1	0	1	2	5	B
50	Sea water	1	0	0	0	0	1	E
53	Fresh water	0	0	0	0	0	0	E
55	Steam	1	0	1	1	0	3	C
56	Open drain	0	0	0	0	1	1	E
57	Closed drain	0	0	0	0	1	1	E
62	Diesel oil	0	0	0	0	2	2	D
63	Compressed air	1	0	0	1	0	2	D
64	Inert gas	1	0	0	1	0	2	D
71	Fire water	1	0	0	0	0	1	E

Table 5.4: Consequence of failure – Plant and piping

6. CRITICALITY RANKING

Criticality may loosely be defined as the product of consequence of failure and likelihood of occurrence. The resulting number is useful for ranking the criticality of components Items but it should not be assumed to hold any absolute significance.

6.1 Structural Items

Section 4.1 presented the findings of topsides inspections in terms of reported anomalies. These findings, together with engineering judgment, were used to assign a likelihood of failure against various components in terms of three numbers:

1 - Occurs quite often
2 - Occasionally happens
3 - Rarely occurs.

The consequence of failure has been discussed in the Section 5.2. The methodology set out therein also results in three numbers to assign the consequence level. The two sets of numbers can then be entered into the risk matrix, shown in Figure 6.1, to establish the criticality ranking. Three levels of criticality (high, medium and low) are indicated. Table 6.1 presents the results of applying this process to the structural items previously considered.

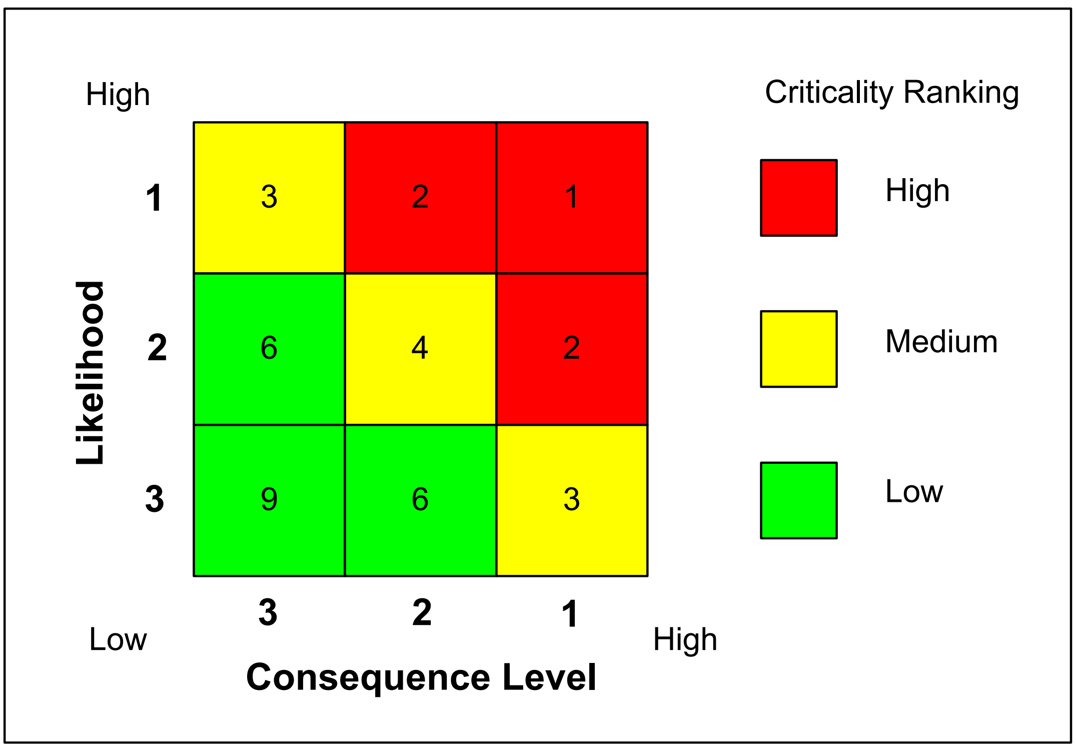


Figure 6.1: Matrix for establishing criticality ranking

Component / Item	Class.	Consequence level for platforms categorized as:			Likeli-hood	Consequence*Likelihood for platforms categorized as:		
		L-1	L-2	L-3		L-1	L-2	L-3
Primary structural framing	A	1	1	1	3	3	3	3
Secondary & tertiary structural framing	B	1	1	2	2	2	2	4
Leg/pile weld connection	B	1	1	2	3	3	3	6
Bridges & associated support structure / bearings	B	1	1	2	3	3	3	6
Boat landings & fenders	D	2	2	3	1	2	2	3
Crane pedestals	C	1	2	2	3	3	6	6
Derrick substructure & skid beams	E	3	3	3	2	6	6	6
Flare/vent towers	B	1	1	2	3	3	3	6
Communication towers	D	2	2	3	3	6	6	9
Deck plating/grating	A	1	1	1	1	1	1	1
Helideck & safety nets	A	1	1	1	1	1	1	1
Walkway grating & supporting structure/hangers	A	1	1	1	1	1	1	1
Handrails incl. posts	A	1	1	1	1	1	1	1
Stair treads & stair stringers	B	1	1	2	1	1	1	2
Swing ropes	A	1	1	1	1	1	1	1
Survival craft & davits	B	1	1	2	3	3	3	6
Access platforms & attachment pts.	A	1	1	1	2	2	2	2
Pipe racks	C	1	2	2	3	3	6	6
Pipework supports	B	1	1	2	2	2	2	4
Risers & supports	A	1	1	1	2	2	2	2
J-tubes & supports	D	2	2	3	2	4	4	6
Conductors & supports	D	2	2	3	1	2	2	3
Service caissons & supports	D	2	2	3	1	2	2	3
u/w cathodic protection system	E	3	3	3	2	6	6	6

Table 6.1: Criticality Ranking of structural components

Criticality Ranking

High

Medium

Low

The criticality ranking of the various components as indicated by the colored cells in Table 6.1 appear to be generally sensible. As can be seen, the criticality rankings (high, medium and low) change according to the platform exposure level in a rational manner.

The Table identifies a number of safety critical elements (SCE's) by red cells as follows:

- For all platforms
    - Deck plating / grating
    - Helideck and safety nets
    - Walkway grating and associated supporting structure
    - Handrails including posts
    - Stair treads and stringers
    - Swing ropes
    - Access platforms and attachment points
    - Risers and supports
- For platforms of exposure levels L-1 and L-2 only
    - Secondary and tertiary structural framing
    - Boat landings and fenders
    - Pipework supports
    - Conductors and supports
    - Service caissons and supports.

It should be noted that the above SCEs and the criticality ranking presented in Table 6.1 are guidelines only. Each installation should be individually appraised and the guidelines adjusted to suit the particular circumstances of the installation. For example, consider a connection within the primary structural framing. This has been assigned to be a medium risk in Table 6.1. However, if it has a very high utilization factor or has a low estimated fatigue life, then consideration should be given to re-classifying it as a high risk. By this means, it will ensure that at least a visual inspection is carried out at regular intervals (i.e. annually) to identify degradation mechanisms (corrosion involving metal loss or fatigue cracking), or additional loading, that may be addressed before more severe consequences ensue.

6.2 Operating Plant and Piping

Criticality Ranking: High (red), Medium (yellow), Low (green)

No.	System description	Class	Platform Consequence Level L-1	L-2	L-3	Likeli-hood	Platform Risk L-1	L-2	L-3
13	Riser and well topside	A	1	1	1	2	2	2	2
20	Separation and stabilization	A	1	1	1	1	1	1	1
21	Crude handling and metering	B	1	1	2	2	2	2	4
23	Gas compression / re-injection	A	1	1	1	1	1	1	1
24	Gas treatment	B	1	1	2	2	2	2	4
25	Gas conditioning	B	1	1	2	2	2	2	4
27	Gas export and metering	A	1	1	1	2	2	2	2
28	Gas sweetening	B	1	1	2	2	2	2	4
29	Water injection	D	2	2	3	2	4	4	6
30	Oil export line	B	1	1	2	1	1	1	2
31	Condensate export line	B	1	1	2	1	1	1	2
32	Gas export pipeline	A	1	1	1	2	2	2	2
33	Oil storage	B	1	1	2	2	2	2	4
36	Wellstream pipeline	A	1	1	1	2	2	2	2
37	Gas injection / lift pipeline	A	1	1	1	1	1	1	1
38	Glycol / methanol regeneration	B	1	1	2	2	2	2	4
40	Cooling medium	E	3	3	3	3	9	9	9
41	Heating medium	D	2	2	3	3	6	6	9
42	Chemical injection	C	1	2	2	3	3	6	6
43	Flare / vent	A	1	1	1	2	2	2	2
44	Oily water	E	3	3	3	2	6	6	6
45	Fuel gas	B	1	1	2	1	1	1	2
50	Sea water	E	3	3	3	3	9	9	9
53	Fresh water	E	3	3	3	3	9	9	9
55	Steam	C	1	2	2	2	2	4	4
56	Open drain	E	3	3	3	3	9	9	9
57	Closed drain	E	3	3	3	3	9	9	9
62	Diesel oil	D	2	2	3	2	4	4	6
63	Compressed air	D	2	2	3	3	6	6	9
64	Inert gas	D	2	2	3	3	6	6	9
71	Fire water	E	3	3	3	3	9	9	9

Table 6.2: Criticality Ranking of process systems

The methodology adopted for the structural components was followed for the process systems (Section 6.1) from which Table 6.2 was derived:

1. Platform consequence levels were computed, based on the consequence classes determined in Table 5.4, using the matrix given in Figure 5.1.
2. Likelihood numbers (1=high, 2=medium, 3=low) were then assigned to each system based on Figure 4.12 and Figure 4.13.
3. From these values, the platform risk number for each system was computed, based on Risk = Likelihood x Consequence (Table 6.2).
4. The criticality ranking was then allocated using Figure 6.1.

Table 6.2 identifies a number of safety critical elements (SCE’s) by red cells as follows:

- For all platforms
  - Riser and wells topsides
  - Separation and stabilization
  - Gas compression / re-injection
  - Gas export / metering
  - Oil / condensate / gas export lines
  - Flare / vent
  - Fuel gas
  - Wellstream
  - Gas injection / lift
- For platforms of exposure levels L-1 and L-2 only
  - Crude handling
  - Gas treatment / conditioning / sweetening
  - Oil storage
  - Glycol / methanol regeneration
- For platforms of exposure levels L-1 only
  - Steam

As noted previously, these risk levels are for guidance only. The plant and piping risks relate purely to the system pressure integrity. On this basis, the direct risk to personnel or the environment of the firewater system leaking is small, but for risk mitigation reasons the firewater system is always regarded as safety critical.

7. HT/HP PRODUCTION ON EXISTING PLATFORMS

High temperature and high pressure (HT/HP) most concern drilling and well completion design [52, 53]. However, there are consequential effects on the associated production facilities, depending on reservoir chemistry and the nature of the facilities. Initial HT/HP production has been through fixed platforms [54] but there is a growing interest in the use of HT/HP subsea completions [55, 56].

7.1 Temperature Effects

The elevated temperatures (downhole in excess of 300ºF) [52] can affect material performance both through direct physical action and through chemical behavior. Some of the particular concerns are listed below.

7.1.1 Seals

Elastomeric seals (and similar elastomeric applications such as flexible hoses) can be designed for high temperature operation but the long-term performance and tolerance to large temperature variation is uncertain. For this reason, metal-to-metal seals have generally been preferred. Similar concerns, however, have been expressed about long-term durability of dynamic metal-to-metal seals [52, 53]. Plastic (Teflon) appears to provide a satisfactory answer in certain applications such as valve stem seals, casing packoffs and hanger seals [55].

7.1.2 Corrosion and material selection

Elevated temperatures can lead to faster corrosion rates. Increased levels of CO_2 and H_2S have also been associated with some HT/HP reservoirs. The use of "exotic" materials such high chrome steels, clad pipe and thermally sprayed aluminum is sometimes necessitated [53, 54].

7.1.3 Thermal expansion

Higher operating temperatures result in increased expansion and potential for pipe overstressing or buckling. These are of particular concern for wellstream flowlines. Typically, on an HT/HP platform, generous expansion loops are built into the choke-to-manifold pipe runs, taking up considerably more "real estate" than conventional well production.

7.1.4 Wax control

Maintaining an elevated temperature may be critical for assuring flow, and pipework may require insulation. It can, however, be hard to preserve temperature during production turndown or at start up, and consequently extensive use of chemicals may on occasion be required to prevent waxing [54].

7.2 Pressure Effects

The elevated pressures (wellhead shut in pressure (WHSIP) greater than 10,000psi) [52] are of main concern with respect to the safety of operations, and emergency relief/shutdown. Higher pressures have obvious ramifications for hydrocarbon containment, both in terms of ensuring adequate wall thickness and in achieving satisfactory containment at seals, gaskets and other pressure boundary breaks.

7.2.1 Well logging and workover

Well logging and workover at high pressures (and temperatures) present both technical and safety challenges, with conventional equipment not being suitable. One option is simply to wait until surface pressures are below 10,000psi [53].

7.2.2 Flow rates / erosion

Higher pressures can lead to accelerated flows in the vicinity of wellheads and through chokes, resulting in severe erosion – particularly if sand is present. This may require careful management to reduce sand production, and/or design to reduce particle acceleration at tees and elbows. API RP 14E provides guidance on limiting erosional velocities, based on fluid density and an empirical constant [57]. There is some lack of consensus, however, regarding the value of the constant [58].

7.2.3 Test separation / flow metering

From a safety perspective, the increased pressures make it desirable to minimize the platform hydrocarbon inventory and level of operator intervention. A way of achieving these has been to use multiphase metering in place of test separation [54].

7.2.4 HIPPS / relief systems

Production facilities and pipelines need to be protected from over-pressurization. An obvious way to do this is to design for the WHSIP but this can lead to excessive platform weight and field development costs. An alternative is to install a full flow pressure relief system, but again, the size of the flare boom and scrubber needed for the maximum flow rates can make a project uneconomic.

The accepted alternative is to use a “high integrity pressure protection system” (HIPPS), which relies on a high reliability instrumented shutdown for the protection of downstream equipment. [54]. HIPPS shutdown valves need to be sufficiently fast actuating and/or sufficiently far downstream of the wellheads to ensure containment before the process facilities are effected by a pressure surge. On smaller facilities, this may be hard to achieve due to insufficient pipe-run. A compromise may be reached whereby part of the system is designed for the WHSIP and part is protected by HIPPS.

7.3 Use of Existing Platforms for HT/HP

An operator wishing to route HT/HP production through existing infrastructure will have to take into account all the above issues. It will be necessary to reanalyze the process system for the new flow conditions, and to perform a new HAZOP for the modified facilities.

An essential part of this will be to obtain a reliable assessment of the existing condition of the pipework and vessels. Given that this study points to internal corrosion as being the prime cause for concern, a detailed *internal* survey will always be necessary. A Level 1 survey will not be sufficient in itself.

8. GUIDELINES FOR ABOVE WATER (API LEVEL I) INSPECTION

8.1 Introduction

Section 8 presents a discussion on the principles that should be considered for future inspection of offshore platform topsides. Also presented, for discussion purposes, is a possible inspection procedure. It is intended that this procedure be used as a basis to solicit industry input and develop a more beneficial inspection methodology.

The main principles, observed from this work, which should be considered when developing inspection requirements, are:

- A large proportion of the reported anomalies are due to external corrosion.
- A large proportion of the reported anomalies are piping related.
- Only a small percentage of the piping anomalies led to failure.
- Although a smaller number of anomalies were due to internal corrosion, a high percentage of them resulted in failure.
- Operators concentrate mainly on structural inspection when performing the yearly API Level 1 inspection.
- Corrosion is the main anomaly for the structure.
- There is strong correlation between the type of equipment on a platform and the risk of a fire and explosion incident (Ref Belmar).
- The structural paint system is rarely repaired immediately, the paint-damaged area will either be cordoned off or the painting fitted into a planned campaign.
- Inspection data and platform inventory are rarely rigorously reviewed in order to carry out future maintenance activities.
- The Level 1 survey reports are often similar and report the same anomalies from successive surveys.

From the above, it can be seen that the current inspection methodology for topsides commonly comprises an API Level 1 survey of the structure operability and the paint system condition. As such, this survey will not address many of the anomalies recorded on the Global X-Ray database and yet a large proportion of them would be identified by visual examination. Hence it would seem that a more rational, risk based approach should be achievable.

8.2 Risk Based Inspection Approach

The following checklist is offered for discussion for inclusion in a revised risk based inspection approach:

- Offshore topsides inspection to also encompass structural, equipment, vessels, cabling, piping, valves, etc.
- Evaluate and risk rank critical components.
- Establish current platform usage, e.g. higher or lower operating pressures and flow rates compared with original design.
- Evaluate platform condition based on previous surveys.
- Set the inspection requirements.
- Set the inspection interval.
- Formulate and set down the inspection plan.
- Feedback into subsequent inspection plans.

For each platform, it is proposed that an inspection plan is initially developed by consideration of the potential risks or critical elements that may contribute to the occurrence of an anomaly. The following factors would typically be considered in the assessment of critical elements:

- Facility age, maintenance regime and condition.
- Type of facility, i.e. manned or unmanned.
- Oil and or Gas throughput
- Equipment inventory
- Import/Export risers

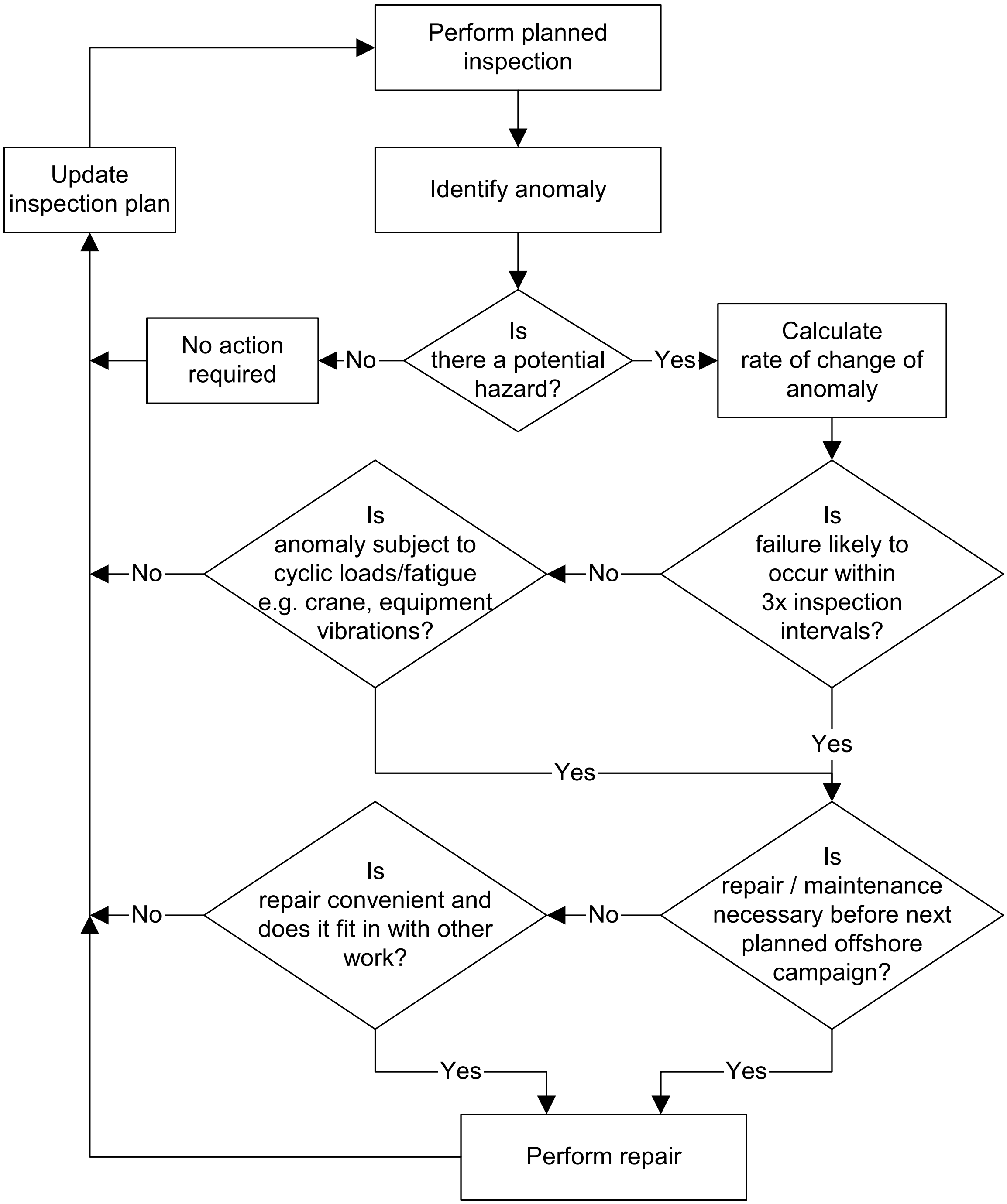
The inspection plan could be developed as a rolling program, such that the frequency of inspection of the various elements would be based on the risk evaluation. A proposed methodology for risk based assessment of structural and process systems is given generally in Section 6 and more specifically in Tables 6.1 and 6.2 respectively.

This inspection plan would be continually updated to reflect the ongoing inspection results as they become available.

8.3 Inspection Assessment and Feedback

This section offers suggestions for analysing inspection results for the purpose of identifying repair and/or maintenance needs and also to provide feedback into the inspection program.

A suggested route to take in assessing results of an existing inspection program is given in the flowchart on the next page. The steps and decisions presented will be dependent, amongst other factors, on operating philosophy and the extent of technical back up available, but they can be tailored to meet Operator needs.



Inspection Feedback Flowchart

Priorities for Action

Anomalies can be prioritized and graded. A suggested grading system is presented in the following table.

Priority Ranking	Description	Action
1	An anomaly presenting an immediate danger to personnel, equipment or the environment.	Anomaly to be brought to the immediate attention of the Offshore Installation Manager (OIM). Immediate action required to eliminate/ minimize the risk to personnel, equipment or the environment Requires immediate engineering evaluation to implement appropriate action to rectify the anomaly.
2	An anomaly presenting a potential future danger to personnel, equipment or the environment.	Depending on the type of anomaly temporary remedial action may be required and/or a further detailed survey may be conducted followed by an engineering evaluation. The anomaly shall be rectified at the earliest opportunity minimizing risk to personnel, equipment or the environment.
3	An anomaly that with little or no attention could progress to the priority 2 status before the next inspection.	Depending on the type and extent of anomaly a further detailed survey may be conducted followed by an engineering evaluation. The anomaly shall be rectified or monitored at the time of the next planned inspection subject to the results of the evaluation.
4	No specific action required.	Include in inspection report with photograph to verify condition.

Table 8.1 Priorities for Action

Review of Inspection Reports

In line with the methods discussed in this document and the above, if an anomaly has a high priority ranking then it demands immediate attention as it may present a hazard. Examples of such cases would be loss of wall thickness on primary structural steelwork, high pressure piping, pressure vessels, fire water mains piping, helideck structure, survival craft and/or davit support steelwork.

Hazard Assessment

The next step within the assessment is to evaluate the anomaly to determine if indeed it does not represent an immediate hazard, this will include considerations of:

- Consequence of failure to personnel and the environment.
- Pressure/temperature/load level at which the component is operating (is it more or less than it was designed for).
- Economic impact (loss of asset, loss of revenue).
- The remaining platform life.

Clearly, after this stage of assessment, if an anomaly does not present an impending hazard then no direct action is warranted and the inspection programme can be maintained (or re-planned to monitor the anomaly more closely if warranted).

It is worth revisiting previous inspection reports at this stage to determine the rate of change in the anomaly with time, if it is of constant magnitude then it may have been a one off event that is not escalating and the inspection plan can be modified to give the anomaly less focus.

Remedies for Hazardous Anomalies

If however the anomaly has shown deterioration with time, then an estimate of when it will become critical must be made. This may be done by projecting the growth of the anomaly and comparing the future degraded strength with the capacity of the component to withstand the current loads/pressures/temperatures. If failure is predicted within a certain period, say before the next planned inspection for the item, then it can be considered that failure is possible. Therefore, for the purposes of this assessment, a detailed review of adequacy, consequence and mitigation is warranted. If the anomaly is not subject to cyclic loads or fatigue, as for example would be generated by a crane or vibrating equipment, and a detailed review shows that there is sufficient residual strength, then immediate intervention may not be required and repair and/or maintenance can be scheduled at a more convenient time with other planned work. However, the inspection plan may need to be modified to highlight it and monitor the changes. At the other extreme, if the anomaly is growing quickly and is likely to continue to do so then it should be repaired in the next planned repair and/or maintenance campaign, when time permits, or alternatively, with a special intervention. Once repair has been completed, then the inspection plan can be modified to reflect the reduced importance now placed on this item.

Summary

In the methodology described above, a rolling program is developed and maintained in which anomalies are identified, categorized, prioritized, remedied and ultimately re-classified with time. There is a certain amount of engineering judgment that will be required from the operatives, but with effort and input over a period of time and using inspection results from other platforms within the operator's fleet, patterns of causes of anomalies and their growth rates will emerge.

The knowledge gained will benefit Operators by enabling them to further optimize inspection programs as well as provide input to new designs and construction methods.

8.4 Assessing the Priorities for Action from Inspection Reports

There are analytical tools available, such as reserve strength assessment, as part established methods for interpreting substructure inspection results. There is no established practice however, for the assessment of topside inspection results and therefore a risk-based approach is likely to be more appropriate depending on the consequence and impact of failure of a particular component. It is anticipated that such an approach as proposed here, will:

- Formulate a rational, practical and well structured inspection programme.
- Base the inspection program on a fit-for-purpose goal.
- Base the inspection program on reliable anomaly growth rate measuring.
- Make use of a reliable and retrievable database.
- Utilize inspection results to optimise future inspection programmes.
- Reduce unnecessary inspection.
- Target high-risk areas for closer inspection.
- Lead to a safer operating regime.

9. SUMMARY RESULTS AND CONCLUSIONS

Whereas considerable effort has in recent years been expended on the integrity assurance of offshore jackets, little has been directed towards topsides facilities and the linkage of routine inspection practices with defect evaluation and integrity management. A likely increase in HT/HP production places new emphasis on determining its effect on the integrity management process. Further, there is wide recognition of the importance of competent personnel and the need to define baseline qualifications and training consistent with the HSE expectations of industry, regulatory bodies and the public.

The work has included an extensive literature review and a number of interviews to identify current code requirements and industry practice. From a regulatory perspective, inspection of facilities in the Outer Continental Shelf (OCS) falls within the scope of Title 30 Code of Federal Regulations, Chapter II, Part 250. In addition to specifically identified requirements, the regulations incorporate provisions from other recognized industry codes and practices. With reference to topsides structures, the regulations make use of API RP2A Section 14 (Surveys). The level of inspection for topsides facilities varies according to the type of equipment or system function. Of particular concern are platform cranes, pollution prevention, drilling operations, well completions, and safety systems.

To explore the availability and application of standards within the industry, use was made of a recent study of fabrication and in-service inspection practices for topsides structural components undertaken for the U.K. Health and Safety Executive. For this a number of international, pan-national and national documents were examined to identify clauses relevant to material classification, categorization of components, recommended inspection techniques including procedures, inspector qualifications, reject/acceptance criteria, and in-service inspection requirements. The extent of coverage by these documents is quite variable. For in-service inspection of topside structures the standards provide far less guidance than for fabrication inspection. The frequency of in-service inspections for topsides generally follows as an add-on to that for the jacket. This is likely to be both inefficient and ineffective for topsides, which need a program relating specifically to the component in-service safety criticality.

With regard to topsides equipment standards, API provides extensive guidance, although for the most part this is non-mandatory. API RP 572 presents the recommended practice for the inspection of pressure vessels. Included in this category are towers, drums, reactors, heat exchangers, and condensers. For inspection frequencies based on corrosion-rate determination, API 510 Pressure Vessel Inspection Code is applicable. This permits an inspection interval based on the calculated remaining life of the vessel and the risk class. In a similar fashion, API RP 574 covers the inspection of piping, tubing, valves (other than control valves) and fittings, with API 570 Piping Inspection Code giving inspection frequencies based on corrosion-rate determination and class. The recommended testing and maintenance of pressure relief devices is given API RP 576. Finally, the inspection and maintenance of atmospheric storage tanks is commonly performed in accordance with API Std 653. It includes sections on inspection (external, internal and frequency), examination and testing in accordance with API Std 650.

Two further recommended practices are of relevance in this context. API RP 579 provides extensive guidelines and methodologies for the quantitative assessment of flaws and damage found in-service within pressurized systems. API RP 580 is the recently developed recommended practice for performing risk-based inspection (RBI).

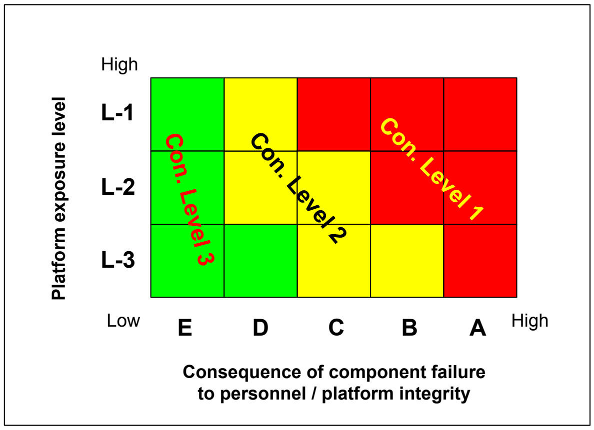
The likelihood of topsides damage or degradation has been estimated from MSL in-house data and industry feedback. MSL has compiled a reliable, industry-wide database from the collective inspection data amassed by industry over the last ten years and beyond. The database includes data from the MMS, CAIRS, and operators. The data relevant to topsides structures inspection was extracted and carefully reorganized into a more useful form for assessing the reported incidents. The original data were filtered and broken down into both anomaly type and structural component. It was found that handrails were responsible for 25% of the reported anomalies and structures for 13%. Of these anomalies the leading two attributors appear to be corrosion at 40% and separation/missing items at 23%.

To assist in the determination of topsides systems failure probabilities, MSL acquired from Global X-Ray & Testing Corporation a mechanical integrity database, comprising 1,960 anomalies recorded in the Gulf of Mexico between 1995 and 2003. It should be understood that anomaly probabilities generated from this database are a simple count of the failures versus total defects recorded. They have not been normalized with reference to the number of systems or equipment items in operation. Thus the system failure statistics derived from the database do not represent the relative safety of an individual system but should represent the relative number of that system type failing in the Gulf of Mexico as a whole, oil separation system failures being the most commonly occurring. For this reason, the system failure rates were compared with HSE data, based on leaks/system year. According to this source, gas compression has the highest rate per system.

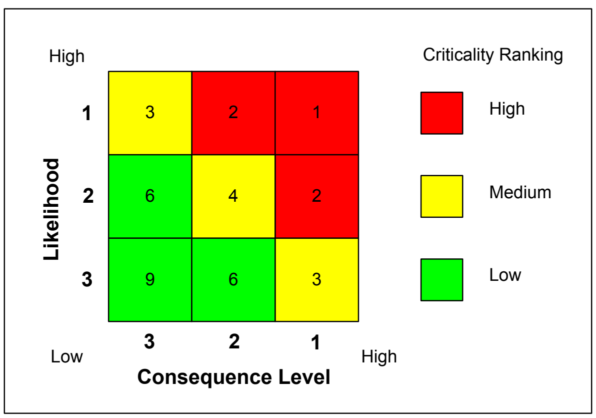
These findings, together with engineering judgment, were used to assign a likelihood of failure against various components in terms of three numbers (1-often, 2-occasionally, and 3-rarely).

The consequence of topsides damage or degradation has been assessed with respect to safety, the environment, business disruption and reputation. Topsides structural components and other items that are typically inspected have been classified according to the consequence of their failure (A being the highest consequence and E the lowest). These classes have been assigned on the basis of personnel safety and loss of hydrocarbon inventory but not on economic grounds. A similar approach has been adopted for the topsides facilities. The consequence class has been determined on a system basis, taking into account five weighted parameters: operating pressure, inventory volume, temperature, fluid phase and hydrocarbon content.

The consequence of a particular component failing may also be considered a function of the platform exposure level as defined by the L-1, L-2 and L-3 levels in API RP2A, the platform exposure level modifying the failure consequence of a particular component. For example, the failure of a pipe support on a low consequence (L-3) platform is not as severe as a similar failure on a high consequence platform. On the other hand, the failure of a walkway grating leads to similar consequences (potential fatality) on both L-1 and L-3 platforms. To accommodate these differences, a "Consequence Matrix" was developed. The matrix outputs one of three consequence levels (1 to 3). Inspection of the figure reveals that components assessed as being of Consequence Class A, such as primary structure, remain at the highest Consequence Level 1, no matter what the platform exposure level is. Components initially assessed as Class B, such as secondary structural framing, are given the highest Consequence Level 1 for platform exposure levels L-1 and L-2, and the medium Consequence Level 2 for a platform exposure of L-3.



This has allowed a critically ranking of the relevant components of the topsides structure, piping and plant, based on a risk assessment approach, and the identification of Safety Critical Elements.



From the Likelihood Number and the Consequence Level the risk can be determined (Risk = Likelihood x Consequence) and the criticality ranking obtained from the risk matrix. Three levels of criticality (high, medium and low) are indicated. The following tables present the results of this process to the topsides items previously considered.

Criticality Ranking

- High
- Medium
- Low

Component / Item	Class	Platform Consequence Level			Likeli-hood	Platform Risk		
		L-1	L-2	L-3		L-1	L-2	L-3
Primary structural framing	A	1	1	1	3	3	3	3
Secondary & tertiary structural framing	B	1	1	2	2	2	2	4
Leg/pile weld connection	B	1	1	2	3	3	3	6
Bridges & associated support structure / bearings	B	1	1	2	3	3	3	6
Boat landings & fenders	D	2	2	3	1	2	2	3
Crane pedestals	C	1	2	2	3	3	6	6
Derrick substructure & skid beams	E	3	3	3	2	6	6	6
Flare/vent towers	B	1	1	2	3	3	3	6
Communication towers	D	2	2	3	3	6	6	9
Deck plating/grating	A	1	1	1	1	1	1	1
Helideck & safety nets	A	1	1	1	1	1	1	1
Walkway grating & supporting structure/hangers	A	1	1	1	1	1	1	1
Handrails incl. posts	A	1	1	1	1	1	1	1
Stair treads & stair stringers	B	1	1	2	1	1	1	2
Swing ropes	A	1	1	1	1	1	1	1
Survival craft & davits	B	1	1	2	3	3	3	6
Access platforms & attachment pts.	A	1	1	1	2	2	2	2
Pipe racks	C	1	2	2	3	3	6	6
Pipework supports	B	1	1	2	2	2	2	4
Risers & supports	A	1	1	1	2	2	2	2
J-tubes & supports	D	2	2	3	2	4	4	6
Conductors & supports	D	2	2	3	1	2	2	3
Service caissons & supports	D	2	2	3	1	2	2	3
u/w cathodic protection system	E	3	3	3	2	6	6	6

Criticality Ranking

Red	High
Yellow	Medium
Green	Low

No.	System description	Class	Platform Consequence Level			Likeli-hood	Platform Risk		
			L-1	L-2	L-3		L-1	L-2	L-3
13	Riser and well topside	A	1	1	1	2	2	2	2
20	Separation and stabilization	A	1	1	1	1	1	1	1
21	Crude handling and metering	B	1	1	2	2	2	2	4
23	Gas compression / re-injection	A	1	1	1	1	1	1	1
24	Gas treatment	B	1	1	2	2	2	2	4
25	Gas conditioning	B	1	1	2	2	2	2	4
27	Gas export and metering	A	1	1	1	2	2	2	2
28	Gas sweetening	B	1	1	2	2	2	2	4
29	Water injection	D	2	2	3	2	4	4	6
30	Oil export line	B	1	1	2	1	1	1	2
31	Condensate export line	B	1	1	2	1	1	1	2
32	Gas export pipeline	A	1	1	1	2	2	2	2
33	Oil storage	B	1	1	2	2	2	2	4
36	Wellstream pipeline	A	1	1	1	2	2	2	2
37	Gas injection / lift pipeline	A	1	1	1	1	1	1	1
38	Glycol / methanol regeneration	B	1	1	2	2	2	2	4
40	Cooling medium	E	3	3	3	3	9	9	9
41	Heating medium	D	2	2	3	3	6	6	9
42	Chemical injection	C	1	2	2	3	3	6	6
43	Flare / vent	A	1	1	1	2	2	2	2
44	Oily water	E	3	3	3	2	6	6	6
45	Fuel gas	B	1	1	2	1	1	1	2
50	Sea water	E	3	3	3	3	9	9	9
53	Fresh water	E	3	3	3	3	9	9	9
55	Steam	C	1	2	2	2	2	4	4
56	Open drain	E	3	3	3	3	9	9	9
57	Closed drain	E	3	3	3	3	9	9	9
62	Diesel oil	D	2	2	3	2	4	4	6
63	Compressed air	D	2	2	3	3	6	6	9
64	Inert gas	D	2	2	3	3	6	6	9
71	Fire water	E	3	3	3	3	9	9	9

Based on this work, an improved API Level 1 survey procedure has been proposed focused on the critical topsides components, with suggested survey techniques and data recording methods.

An operator wishing to route HT/HP production through existing infrastructure will have to address issues such as sealing, corrosion, expansion, waxing, logging, workover, erosion, metering, shutdown, and pressure relief. It will be necessary to reanalyze the process system for the new flow conditions, and to perform a new HAZOP for the modified facilities. An essential part of this will be to obtain a reliable assessment of the existing condition of the pipework and vessels. Given that this study points to internal corrosion as being a prime cause for concern, a detailed internal survey will always be necessary. A Level 1 survey will not be sufficient.

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APPENDIX A

REVIEW OF SELECTED STRUCTURAL CODES FOR IN SERVICE INSPECTION

A.1 Introduction

A review of inspection practices was carried out and summarized in Section 2.2. The findings of this examination with respect to the API, NORSOK and ISO codes is reported individually and summarized within this appendix.

A.2 API RP 2A WSD

This Recommended Practice forms the original source documents for most offshore design and construction practice. A clear attempt is made to assign material and inspection requirements during construction in relation to service duty, material thickness, restraint and structural redundancy. Topside functions are however treated in a relatively cursory and dismissive manner (Ref. Clauses 8.1.1, 8.1.3.a).

In-service inspection is specifically covered in Section 14. The Approach of Section 14, clause 14.5 is sound, correctly proposing that critical areas for inspection should be identified in design or assessment, but the general bias of Section 14 towards substructure would make its application to topsides less likely in practice. The lack of any direction as to the contents of a design report in any other section of API RP2A is clearly a weakness in this respect – as this would be an essential document to ensure compliance. Section 14 includes the guidance that "During the life of the platform, in-place surveys that monitor the adequacy of the corrosion protection system and determine the condition of the platform should be performed in order to safeguard human life and property, protect the environment, and prevent the loss of natural resources". This sound philosophy is diluted somewhat by the subjective classification of "more critical areas" in section 14.3.1 as "deck legs, girders, trusses, etc".

Clause 14.3 provides details on the extent of the surveys that are to be carried out. These requirements demand that four periodic inspection levels at certain time intervals are defined. Details of these requirements have been summarized in

Table A.1 and

Table **A.2** below. It is noted in Clause 14.4 that the time intervals stated, as shown in

Table A.1, are not to be exceeded unless experience and/or engineering analyses indicates otherwise. If different intervals are to be implemented then justification for doing so is to be documented and retained by the operator. In producing this documentation a number of factors should be taken into account as follows:

i. Original design/assessment criteria.

ii. Present structural condition.

iii. Service history of platform (condition of corrosion protection system, results of previous inspections, changes in design operating or loading conditions, prior damage and repair, etc.).

iv. Platform structural redundancy.

v. Criticality of the platform to other operations.

vi. Platform location (frontier area, water depth, etc.).

vii. Damage.

viii. Fatigue sensitivity.

It may be noted that the LRFD version of API RP2A gives a slightly different list of factors to be considered:

i. Consequence of failure to human life, property, the environment, and/or conservation of natural resources.

ii. Manned or unmanned platform.

iii. Wells (naturally flowing, sour gas high pressure, etc.).

iv. Original design criteria.

v. Present structural condition.

vi. Service history of platform (condition of corrosion protection system, results of previous inspections, changes in design operating or loading conditions, prior damage and repair, etc.).

vii. Platform structural redundancy.

viii. Criticality of the platform to other operations.

ix. Platform location (frontier area, water depth, etc.).

Exposure Level	Category	Survey Level I	Survey Level II	Survey Level III	Survey Level IV
L-1		1 yr	3 thru 5 yrs	6 thru 10 yrs	*
L-2		1 yr	5 thru 10 yrs	11 thru 15 yrs	*
L-3		1 yr	5 thru 10 yrs	*	*

Table A.1
API RP2A- WSD: Guideline Survey Inspection Intervals

Periodic Survey Levels			
Level I	**Level II**	**Level III**	**Level IV**
The effectiveness of the corrosion protection system employed should be checked and an above water visual survey should be performed annually to detect deteriorating coating systems, excessive corrosion, and bent, missing or damaged members. This survey should identify indications of obvious overloading, design deficiencies and any use, which is inconsistent with the platform's original purpose. This survey should also include a general examination of all structural members in the splash zone and above water, concentrating on the condition of the more critical areas such as deck legs, girders, trusses, etc. If above water damage is detected, nondestructive testing should be used when visual inspection cannot fully determine the extent of the damage. Should the Level I survey indicate that underwater damage may have occurred, a Level II inspection should be conducted as soon as conditions permit.	A Level II survey consists of general underwater visual inspection by divers or ROV to detect the presence of an or all of the following: Excessive corrosion Accidental or environmental overloading occur, seafloor instability, etc Fatigue damage Design or construction deficiencies Presence of debris Excessive marine growth This survey should include the measurement of cathodic potentials of preselected critical areas using divers or ROV. Detection of significant structural damage during a Level II survey should become the basis for initiation of Level III survey. The Level III survey, if required, should be conducted as soon as possible.	A Level III survey consists of an underwater visual inspection of preselected areas and/or, based on results of the Level II survey, areas of known or suspected damage. Such areas should be sufficiently cleaned of marine growth to permit thorough inspection. Pre-selection of areas to be surveyed should be based on an engineering evaluation of areas where repeated inspections are desirable in order to monitor their integrity over time. Detection of significant structural damage during a Level III survey should become the basis for initiation of a Level IV survey in those instances where visual inspection alone cannot determine the extent of damage. The Level IV survey, if required, should be conducted as soon as conditions permit.	A Level IV survey consists of underwater nondestructive testing of preselected areas and/or, based on results of the Level III survey, areas of known or suspected damage, Level IV should also include detailed inspection and measurement of damaged areas.

Table A.2
API RP2A- WSD: In-service Periodic Inspection Requirements

A.3 NORSOK Standards M001, M101, M120, N001/N005, S001 and Z001

These Norwegian Standards are considered here as a group for the purposes of this study. They represent the most extensive and developed public sector standard(s) covering the requirements for inspection during fabrication and operation. They are normative and prescriptive in nature. They clearly identify the link between design knowledge and inspection requirements and give detailed direction on component and joint classification relative to inspection requirements. Within the standards there are a large number of normative references - so many that the realistic ability of a contractor to comply must become questionable. The requirements for topside structures are dealt with more extensively than in other standards but the bias in identifying risk is clearly transferred from substructure design and the issue of system interaction is poorly covered.

NORSOK standard N-005 provides the basis for condition monitoring of load bearing structures throughout the lifetime until decommissioning. The standard is applicable to all types of offshore structures used in the petroleum activities, including bottom-founded structures as well as floating structures. The standard is applicable to condition monitoring of complete structure including substructures, topside structures, vessel hulls, foundations and mooring systems. The objectives of condition monitoring are to ensure that an adequate level of structural integrity is maintained at all times. The standard provides a number of Normative Annexes (B to E), which give additional conditional monitoring requirements specific to jacket structures, Column stabilized units, Ship-shaped units and Concrete structures respectively. Information specific to topsides is not provided although as stated above the main normative section of N-005 is intended to be applicable for topsides.

The IMR (In-service Inspection, Maintenance and Repair) prepared during design should give clear direction relating to the effect of complexity and criticality on inspection assessment and shall cover, as a minimum, the areas such as overall structural redundancy, provisions of critical areas and components, consequences of failure, accessibility, possible repair methods, extent of inspection and inspection methods. Inspection is mandated to be developed on a platform specific basis (see N-005 Cl. 5). The detail condition-monitoring program depends on the design and maintenance philosophy, the current condition, the capability of the inspection methods available and the intended use of the structure. The condition monitoring should determine, within reasonable confidence the existence, extent and consequence of the following items on human life, the environment and assets:

i. Degradation or deterioration due to fatigue or other time dependent structural damage
ii. Corrosion damage
iii. Fabrication or installation damage
iv. Damage or component weakening due to strength overloading
v. Damage due to man-made hazards
vi. Excessive deformation

The condition monitoring is to be continuously updated as it may involve factors in the nature of uncertainty such as environmental conditions, failure probabilities, damage development. In addition a revised program may be necessary as a result of new tools and methods.

An initial condition survey during the first year of operation is recommended followed by a "framework program" for inspections on a 3-5 year cycle (Cl.5.3.1), which is based on the experience obtained from Norwegian petroleum activities. Based on the information gained in the first period of operation and knowledge of the application of new analysis techniques and methods within condition monitoring and maintenance, the interval may be altered. However, a change in the duration of the framework program should be based on maintaining an adequate level of safety and appropriate documentation shall be provided to show this.

Detailed inspection planning is discussed with the proposition that “It may, when appropriate, be practical to differentiate between condition monitoring in the atmospheric zone and in the submerged zone”. The splash zone is separately discussed with the exhortation “Needs for splash zone inspection should therefore be reduced to a minimum”. Instrumentation Based Condition Monitoring (IBCM) is highlighted as being an alternative to conventional inspection methods. The IBCM is considered to be suitable to areas with limited accessibility for performance of condition monitoring and maintenance. Typical applications of ICBM highlighted are strain monitoring of jacket structures, foundation behavior during extreme storm, etc. Methods for topsides inspection are not specified but must be suitable to meet the objectives.

The standard provides information in the form of an informative Annex A on the use of inspection methods for in-service inspection for above water and below water. For above water inspections, general visual and close visual inspection is noted as being required before carrying out any further NDT. Although UT, MP and EC methods are mentioned, caution is noted with regards to use of MT where removal of coatings would be necessary. For surface breaking defects, crack detection may be detected by means of MT or by EC methods. In areas where fatigue resistance needs to be confirmed or where the consequences of developing a crack is unacceptable the use of EC rather than MT are preferred. Information on the use of most widely used methods, (e.g. visual, EC, UT/RT, MP, FMD (Flooded Member Detection), etc.) their capabilities, features and limitations are provided for below water inspection only.

A.4 ISO 13819-1 Petroleum and Natural Gas Industries - Offshore Structures – Part 1: General Requirements

This document specifies general principles. Section 3.2 states "Maintenance shall include the performance of regular inspections, inspections on special occasions (e.g., after an earthquake or other severe environmental event)" but then proceeds to state "Durability shall be achieved by either: a) a maintenance program, or b) designing so that deterioration will not invalidate the state of the structure in those areas where the structure cannot be or is not expected to be maintained." The implications for this statement are clarified further by the following paragraph: "In the first case above, the structure shall be designed and constructed so that no significant degradation is likely to occur within the time intervals between inspections. The necessity of relevant parts of the structure being available for inspection - without unreasonable complicated dismantling - should be considered during design. Degradation may be reduced or prevented by providing a suitable inspection system." The possibility of designing and fabricating to completely avoid in-service inspection is identified here. This is however contradicted in section 8 (see Requirements during Operation - extent of Inspection). A note at the end of section 3.2 says: "Structural integrity, serviceability throughout the intended service life, and durability are not simply functions of the design calculations but are also dependent on the quality control exercised in manufacture, the supervision on site and the manner in which the structure is used and maintained".

Clause 8.3 (In-service inspection, maintenance and repair) states, "Inspection shall be undertaken at regular intervals to check for possible damage or deterioration. Maintenance should be specified accounting for the importance and use, knowledge of the durability of the components, environmental conditions and the protection against external actions. Structural components that are essential to the stability and resistance of a structure should, as far as possible, be accessible for inspection".

A.5 ISO 13819-2 Petroleum and Natural Gas Industries - Offshore structures – Part 2 Fixed Steel Structures

Clause 6.1.2 quotes from ISO 13819-1 (the note at the end of section 3.2). From this is drawn the philosophy that "…during the planning stage a philosophy for inspection and maintenance should be developed. The design of the structure as a whole, as well as the structural details, should be consistent with this philosophy." A systematic classification of "life safety" and "consequence of failure" are proposed to provide a matrix of "exposure levels" that may be used to determine criteria for design. Alternative philosophical approaches to material selection, i.e. Material Category (MC) or Design Class (DC), are proposed.

Inspection during operation is identified as a principal issue from the planning phase. Section 24, In-service inspection and structural integrity management (Cl. 24.8) states that "The inspection strategy should identify the general type of tools/techniques to be used". Specific techniques are discussed in the commentary but this is entirely directed at the substructure. The following methods are discussed: visual inspection, flooded member detection (UT or RT), eddy current inspection, alternating current field measurement (ACFM), alternating current potential drop (ACPD), UT and RT. Criticality classification is discussed under risk assessment in Cl. 24.4.1. Component complexity is not explicitly discussed but should be identified by the required review of design data.

This standard recommends inspection according to a platform specific "structural integrity management plan" in accordance with clause 24.5 and also provides an alternative default inspection program in Cl. 24.7.1.3, which addresses the concerns of safeguarding human life and the environment only. The default inspection program consists of a baseline inspection and four different periodic inspection levels (Level I to Level IV) the details of which have been summarized in Table A.3 and Table A.4 of this report. These periodic inspections are to be carried out within defined periods and are directly linked to the exposure levels of the structure (e.g. L1, L2 or L3) relating to safety of personnel and consequence of failure as shown in Table A.5.

Baseline Inspection
A baseline inspection shall be conducted as soon as practical after the major platform installation, and commissioning. The minimum scope shall consist of: (a) a visual inspection without marine growth cleaning that provides full coverage from mudline to top of jacket of the platform structure (members and joints), conductors, risers, and various appurtenances. This includes benchmarking the seabed conditions at the legs/piles and checking for debris and damage (b) a set of CP readings that provides full coverage of the underwater platform structure (members and joints), conductors, risers, and various appurtenances (c) visual confirmation of the existence of all sacrificial anodes, electrodes and any other corrosion protection material/equipment (d) measurement of the actual mean water surface elevation relative to the as installed platform structure, with appropriate correction for tide and sea state conditions (e) tilt and platform orientation (f) riser and J-tube soil contact (g) seabed soil profile

Table A.3
ISO 13819-2, Part 2: In-service Baseline Inspection Requirements

Periodic Inspection			
Level I	**Level II**	**Level III**	**Level IV**
A visual Inspection without marine growth cleaning of the top of jacket region CP readings of at least one jacket leg using a drop cell or other suitable equipment	The default scope for Level II periodic inspection shall consist of the same scope as the default Level I inspection plus a general visual survey of the full structure with particular attention to members, joints, appurtenances, and appurtenance connections	The default scope for Level III periodic inspection shall consist of the same scope specified for the baseline inspection, plus the following additional items: (a) Flooded member detection (FMD) of the following components that are located underwater and were designed to be non-flooded: at least 50% of all primary structural members, plus key support members for risers, J-tubes, conductors (first underwater framing level only), service caissons, and other appurtenances. (Note: A Level IV periodic inspection, as described below, may be substituted in lieu of this FMD requirement) (b) In lieu of the FMD requirements in a) above, marine growth cleaning and close visual inspection of at least 20 or 5 % of the total population (whichever is smaller) of primary member end connections including a minimum of five primary brace to leg connections (c) Marine growth measurements on selected members at a representative set of elevations from mean sea level to the mudline (d) For platforms with sacrificial anodes: An estimate of the approximate percent in depletion of 100% of anodes (e) For platforms with impressed current systems: Visual survey of the state of the anodes and reference electrodes. Dielectric shields shall also be thoroughly inspected to ensure that they are undamaged, free from discontinuities, and satisfactorily bonded to the structure	The default scope for a Level IV periodic inspection shall consist of the same scope as a Level III default inspection, excluding the Level III requirements a) and b), plus: (a) Marine growth cleaning (as required) and detailed inspection of selected welds at nodal joints (member and connections) and other critical locations using NDE techniques. 100% of the weld length shall be inspected. The degree of marine growth cleaning shall be sufficient to permit thorough inspection

Table A.4
ISO 13819-2, Part 2: In-service Periodic Inspection Requirements

Life Safety Category	Consequence of failure category		
	High Consequence of failure	Medium Consequence of failure	Low consequence of failure
Manned-non-evacuated	L1	L1	L1
Manned – evacuated	L1	L2	L2
Unmanned	L1	L2	L3

Table A.5
ISO 13819-2, Part 2: Exposure Level

A.6 ISO 13819-1.3 Petroleum and Natural Gas Industries - Offshore Structures – Part 1.3 Topside Structures.

The philosophy for inspection and its relationship to design, and in-service conditions is clearly stated (in clause 6.9) as follows:

"During the design, fabrication, inspection, transportation and installation of the topsides, sufficient data shall be collected and compiled for use in preparing in-service inspection programs, possible platform modifications etc. Where a topsides has fatigue sensitive components the critical areas shall be identified and this information used in the preparation of in service inspection programs."

Clause 16.2 clearly states that the structural integrity management plan for the installation should include a structural risk assessment to identify safety-critical components, the failure of which could significantly reduce structural integrity. In assessing safety criticality consideration should be given to components that are subject to high loading, including cyclic loading, corrosion and other defects and the availability of alternative load paths where a structural component may be defective. Clause 16.3 lists areas that need to be taken into account in the case of topside structures. The list appears to be extensive and includes areas such as corrosion protection systems, fire protection systems, supports for equipment including safety critical items, shock/vibration loading, access routes, including floors and gratings, difficult to inspect areas, etc. The topside components that require special attention are noted in Section A.16.3 (informative), and include a number of items as follows:

a) Main deck girders - highly stressed panels

b) Leg transitions to substructures - fatigue in highly stressed stiffened panels

c) Module trusses and support units

d) Accommodation module - anti vibration mountings and support units

e) Drilling rigs - shock loading, wind turbulence

f) Bridges - bearing fatigue, support for both safety critical and hazardous equipment

g) Flare booms and vent stacks - supports to the main deck structure, vortex shedding, strength reduction due to heat

h) Cranes - highly stressed pedestals, fatigue, attachments to main deck structure

i) Helidecks - wind turbulence due to obstruction from surrounding structures and equipment and thermal effects from turbine exhausts

j) Lifeboats and other evacuation, escape and rescue equipment - fatigue cracking of davits

k) Changes to equipment weights and support location points and deck loads.

Clause 16.5 provides alternative default minimum inspection requirements to be used in the absence of a platform specific inspection plan consisting of a baseline inspection and periodic inspections. It is clear from Clause 16.5 that the requirements of Clause 24.7 of ISO 13819-2 relating to periodic inspections should be followed. However, it is noted that these requirements are somewhat simplified for topsides for which the main features have been summarized in Table A.6 of this report. It can be seen from Table A.6 that the emphasis on periodic inspection is mainly confined to the following areas:

i. The continued effectiveness of coating systems (i.e. corrosion protection systems, fire protection systems), without the removal of paint and coatings.
ii. Vulnerability of safety critical equipment and supports to damage from shock or vibration loading
iii. Assessment of missing, bent, or damaged members.

It can be also be observed from Table A.6 that a baseline inspection shall be conducted as soon as possible after installation and no later than one year after installation. The basis of this inspection involves visual inspection only, although it is not clear whether this is to be form of a general or close visual inspection. It can be seen from Table A.6 that general visual inspection is required for all periodic inspection levels, whilst close visual inspection is confined to Level II and III only. From Table A.6 it can be seen that NDT inspection requirements are confined to level II or level III inspections and in the case of level II inspection a minimum of 10% inspection of safety critical elements is required, whilst for level III inspection all safety critical elements are required to be inspected. Reference is made in Clause 16.4 and in the informative Section A.16.4 on the suitability of NDT inspection techniques to be used (i.e. UT, MT and eddy current based techniques). However, the extent of NDT testing and the acceptance criteria is not defined. This may be important particularly for example where safety critical components identified have protective coatings. In such cases the application of certain NDT inspection techniques (e.g. MT) may not be suitable. Furthermore, issues such as whether coatings should be removed to perform inspection, or whether reliance should based on techniques which do not require coating to be removed, may be significant in determining the inspection program to be carried out. Furthermore, certain areas of topsides may be difficult to inspect because of their function and location (e.g. flares, drilling derricks and areas hidden by plant and equipment).

Baseline Inspection	Periodic Inspection (Exposure Levels/Consequence of Failure)			
	Level I	**Level II**	**Level III**	**Level IV**
A baseline inspection to benchmark the installed condition of the topsides structure shall be conducted as soon as possible after first emplacement and commissioning of the topsides facilities, and no later than one year after emplacement. The objective of this inspection is to identify any defects with the potential to impair the integrity of the structure and equipment so as to allow these to be assessed and repaired if necessary before the first periodic inspection. The minimum scope of inspection shall consist of: 1) A visual inspection without removal of paint and coatings of all parts of the topsides structure including facilities structures to check that: i) All Parts of the structure are intact and undamaged, ii) All fixings between structures and between structures and equipment, including gratings and handrails, are secure, iii) Paintwork and protective coatings are not damaged. 2) A walkdown survey to assess the vulnerability of safety-critical equipment and supports to damage from shock loading and strong vibration induced by actions from extreme environmental events and accidental loadings.	The minimum scope shall consist of a visual survey to determine: – The continued effectiveness of coating systems – Any signs of excessive corrosion – The existence of any bent, missing, or damaged members – The survey should identify indications of obvious overloading, design deficiencies and any operational usage that is inconsistent with the original design intent of the installation. – The survey should include a general visual inspection of all areas of structure that have been identified as safety-critical. Should the Level 1 survey indicate that damage might have occurred, level II inspection should be conducted as soon as conditions permit.	The minimum scope shall consist of: – A general visual inspection without removal of paint and coatings of all parts of the topsides structure including facilities (as described in Level 1 inspection). – A close visual inspection of all components identified as safety-critical – Detailed non-destructive examination of a selection of safety-critical components and comprising not less than 10% of all safety-critical structural components. If damage is detected, non-destructive testing of the suspect area should be used where visual inspection alone cannot fully determine the extent of damage.	The minimum scope shall consist of: - A general visual inspection without removal of paint and coatings of all parts of the topsides structure including facilities structures (as described in Levels I and II inspection). - A close visual inspection of all components identified as safety-critical (as described in Levels I and II inspections.). - Detailed non-destructive examination of all safety-critical components	There is no requirement for a Level IV inspection of topsides structures

Table A.6 - ISO/CD 13819-1.3: In-service Inspection Requirements