ED Offshore Inspection Guide

Well Integrity (Operate Phase)

Contents

Summary

This Inspection Guide (IG) sets out the Health and Safety Executive approach to the inspection of well operators' well integrity arrangements for the operate phase of a well lifecycle for wells onshore and offshore in Great Britain.

The Guide provides questions sets to be used as a basis for inspection of the well integrity arrangements. This has been developed from a background of HSE and industry guidance on well integrity.

The guide provides the basis to assess any risk gap as defined by HSE's Enforcement Management Model, and hence the Duty Holder's Performance Score which will feed into the intervention planning process.

Introduction

The most important role of the well-operator is to ensure the integrity of its wells, barriers and the pressure containment boundary throughout the well life cycle from design to final abandonment.

The well-operator should consider the benefits of having a policy defining its commitments and obligations to safeguard health, environment, assets and reputation by establishing and preserving well integrity. This well integrity policy should be endorsed at a senior level within the well-operator's organisation but may sit within a wider policy framework rather than a stand-alone document.

The well-operator is responsible for assessing the well risks and reducing them to ALARP. This should be demonstrated to the offshore installation duty holder who has primary responsibility for the safety of the installation and the personnel on board.

Well-operators should have a system for ensuring well integrity throughout the life cycle. Management of operations may be devolved but the responsibility for the integrity of the well remains with the well-operator.

Well-operators should satisfy themselves that their procedures and processes for complying with all relevant legislation are effective. Those key statutory requirements are:

The Offshore Installations and Wells (Design and Construction, etc) Regulations 1996, as amended, hereafter referred to as DCR [Ref 4] which apply to all oil and gas related wells both onshore and offshore;

The Offshore Installations (Offshore Safety Directive) (Safety Case etc.) Regulations 2015 hereafter referred to as SCR 2015 [Ref 5] which apply offshore in external waters of the UK Continental Shelf.

The Offshore Installations (Safety Case) Regulations 2005 hereafter referred to as SCR 05 [Ref 6] which apply offshore in Great Britain internal waters; and

The Borehole Sites and Operations Regulations 1995 hereafter referred to as BSOR [Ref 7] which only apply onshore Great Britain.

Action

The aim of this Inspection Guide (IG) is to provide information and guidance to inspectors to support the safe operation of hydrocarbon wells. It does this by highlighting key areas required in well integrity schemes, so that these can be covered during inspections, providing a framework for inspectors to judge compliance, assign performance ratings, and decide what enforcement action to take should they find legislative breaches. In doing so, it complements HSE's Enforcement Policy Statement (EPS) and Enforcement Management Model (EMM).

The inspection requires well operators to perform a self-assessment of their Well Integrity Management System (WIMS) to ascertain compliance with relevant standards and guidance [Appendix 1] and provide the associated documentary evidence for further review by the inspector. This review will subsequently be followed by a set of role-specific questionnaires [Appendices 3&4]. The effective management of risk is also critical to impaired wells as they age throughout their life cycle. Wells Risk Management is treated as a separate but complimentary assessment [Appendix 5]. These assessments provide the interpretive standard against which the Enforcement Management Model (EMM) risk-gap should be assessed and hence the Duty Holder's performance Score in relation to well integrity management.

The questions were developed from international standards and guidance and examples of good industry practice; specifically: ISO16530-1-2017 *Well Integrity Part 1: Lifecycle Governance* and Oil and Gas UK *Well Life Cycle Integrity Guidelines, Issue 3*.

Success criteria (fundamental requirements) are listed under the inspection topics [appendix 6]; these cover the key issues that inspectors should consider when carrying-out inspections against each core intervention issue. In some instances, not all of the success criteria will apply so inspectors should make a judgement regarding which of these are relevant in each case. If the relevant success criteria cannot be met, inspectors should assess how serious the consequences of failure to comply could be. This will inform their decision making in terms of the performance ratings that they assign and the enforcement action they take (if any) based on the findings of the inspection.

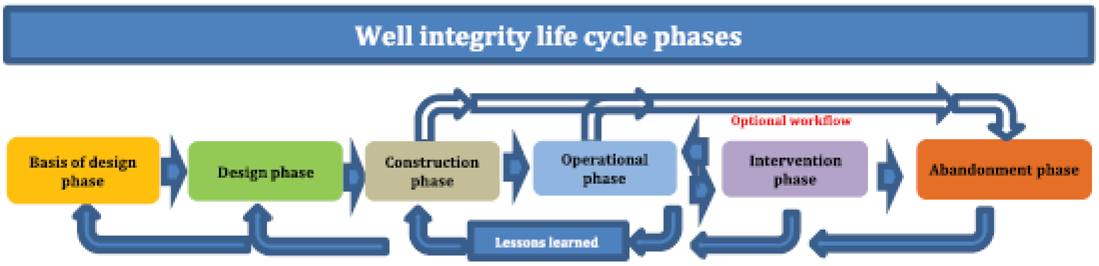
BACKGROUND

The loss of well integrity can result in major accidents and presents a severe risk to the personnel, asset and environment. In the UK, all onshore and offshore well operators must comply with the Offshore Installations and Wells (Design and Construction, etc.) Regulations 1996 (DCR). The DCR place goal-setting duties on well operators, to ensure that there is no unplanned escape of fluids from the well and risks to the health and safety of persons are as low as is reasonably practicable (ALARP) throughout the well lifecycle.

The accepted good practice philosophy is that all wells are to be equipped with two well barriers against the reservoir, and that the well barriers are to be as independent of each other as possible. This ensures no single failure of a component is to lead to unacceptable consequences. If one of the barriers fails, the well has reduced integrity and operations have to take place to replace or restore the failed barrier element. These barriers can deteriorate or its functional efficiency reduced during the well lifecycle resulting in the leakage of hydrocarbons.

The referenced ISO 16530-1-2017 document was prepared by Technical Committee ISO/TC 67, Materials, equipment and offshore structures for petroleum, petrochemical and natural gas industries, Subcommittee SC 4, Drilling and production equipment.

A well lifecycle is detailed below:



This inspection guide is concerned with the operational phase. Wells will spend the vast majority of its life in the operate phase therefore this guide targets the greatest cumulative risk. The design phase, construction, intervention and abandonment phases are inspected through the Well Notification process.

ISO Standards

ISO (the International Organization for Standardization) is a worldwide federation of national standards bodies (ISO member bodies). The work of preparing International Standards is normally carried out through ISO technical committees. Each member body interested in a subject for which a technical committee has been established has the right to be represented on that committee. International organizations, governmental and non-governmental, in liaison with ISO, also take part in the work.

Oil and Gas UK Guidance
The Well Life Cycle Practices Forum (WLCPF) produced guidance on well integrity for Oil and Gas UK. They were written by the Well Integrity Workgroup which included experts from several operators and were reviewed by external stakeholders that included other WLCPF members and the HSE and BEIS.

The ISO Standard and Oil & Gas UK guidance are relevant to;

- all well-operators of GB & UKCS wells
- well integrity during the full lifecycle of the well

The guidelines address arrangements for well integrity, contents of well integrity management scheme, administration of a well integrity management scheme, effective implementation of the well integrity management scheme, wells risk assessments, barriers, component performance standards, operating limits, monitoring and surveillance requirements, wells maintenance, integrity failures, management of change, records, effective audit and review during the relevant phase of the well life cycle.

LEGAL REQUIREMENTS

There is a general duty under Regulation 13 of the Offshore Installations and Wells (Design and construction, etc) Regulations 1996 for the well operator to:

Ensure that a well is so designed, modified, commissioned, constructed, equipped, operated, maintained, suspended and abandoned that:

a) so far as is reasonably practicable, there can be no unplanned escape of fluids from the well; and

b) risks to the health and safety of persons from it or anything in it, or in strata, to which it is connected, are as low as reasonably practicable.

Regulation 16 requires:

The well operator shall ensure that every part of a well is composed of material which is suitable for achieving the purposes described in regulation 13(1)

The Offshore Installations (Offshore Safety Directive) (Safety Case etc) Regulations 2015 requires (at Schedule 6) duty holders of production installations to describe in the safety case how they will comply with the above regulations and a description of how duty holders ensure the suitability of the safety and environmentally critical elements.

Organisation

Targeting

Inspections should be carried-out in accordance with OSDR duty holder intervention plans.

Timing

Inspectors should undertake well integrity inspections as part of the agreed OSDR Intervention Plan; when intelligence indicates intervention is necessary, or as part of an investigation following an incident.

Resources

Resource for the undertaking of well integrity management interventions will be agreed as part of the OSDR Work Plan or by agreement between discipline specialist team-leaders and inspection management team-leaders, as appropriate.

Recording & Reporting

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

References

1. ISO 16530-1-2017 Petroleum and natural gas industries — Well integrity — Part 1: Life cycle governance
2. ISO 5208:2015(E) Industrial valves — Pressure testing of metallic valves
3. BS EN ISO 10417:2004 Petroleum and natural gas industries — Subsurface safety valve systems — Design, installation, operation and redress
4. ISO 17776:2016 Petroleum and natural gas industries – Offshore production installations - Major Accident hazard management during the design of new installations
5. Oil and Gas UK – Well Life Cycle Integrity Guidelines
6. Oil and Gas UK – Guidelines for the Competence of Wells Personnel
7. API Standard 6AV2 Installation, Maintenance, and Repair of Surface Safety Valves and Underwater Safety Valves Offshore (First Edition, March 2014)
8. API Recommended Practice 14B Design, Installation, Operation, Test, and Redress of Subsurface Safety Valve Systems
9. API RP 90 Recommended Practice Annular Pressure Management in Offshore Wells
10. API RP 90-2 Recommended Practice Annular Pressure Management in Onshore Wells
11. A guide to the well aspects of the Offshore Installations and Wells (Design and Construction, etc.) Regulations 1996, L84
12. Offshore Installations (Offshore Safety Directive) (Safety Case etc.) Regulations 2015 – Guidance on Regulations L154

13. Offshore Installations (Safety Case) Regulations 2005
14. Borehole sites and Operations Regulations 1995 – Guidance on Regulations L72

Contacts

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Appendices

Appendix 1 Inspection Guidance – Documentation review & Well Operator self-assessment
Appendix 2 Inspection Guidance – Well Operator self-assessment questionnaire
Appendix 3 Inspection Guidance – Role specific interview outline
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Appendix 1: Inspection Guidance – Documentation Review

The need for a Well Integrity Management System inspection using this guide is likely to be defined by the OSDR intervention planning process but may be implemented separately by HSE wells specialists to respond to: complaints, investigations, newly appointed well operators, changes in well operator's well stock etc.

This appendix details the typical information that should be requested prior to a Well Integrity Management System inspection. The intention is to gauge the robustness of the system, and provide inspectors with information which can inform their questionnaires:

- The well operator should complete the self-assessment questionnaire contained in appendix 2 detailing the documentary evidence for their response. These documents should be sent through for inspection prior to the interviews. These documents are likely to include:
    - A current copy the documents which contain; the Well Integrity Policy, The Well Integrity Strategy and Barrier Management Policy.
    - A current and complete copy of the arrangements for: Well Integrity, Deviations and Dispensations, and associated Risk Assessment
    - Details of the individual position responsible for the management of well integrity during the operate phase of the well lifecycle.
    - A definitive list of wells covered by the arrangements. [Using OGA & company nomenclature]
    - Details of the management of well integrity KPIs including a current well integrity status of the well operator's wells.
    - Two examples of current or recently approved well deviation/dispensation documentation including any relevant supporting documentation and risk assessments.
    - Performance Standards for the wells SECEs during the operate phase.
    - Details of any Remedial Action Requests (RAR) or comments from the Independent Competent Person (ICP) related to the wells from the latest well verification activities

It is anticipated that this documentation may take some time to collate and therefore notification of an inspection and requests for information should be made, wherever possible, in a timely manner when part of the planned intervention strategy.

Inspectors shall review the self-assessment against the provided documentation in advance of the interviews to ensure that clarification questions are raised during those interviews.

Appendix 2: Well Operator Self-Assessment – System Review

	Questions	Model Answer	Evidence and Comments
Well Integrity Policy and Strategy;			
1.	Is the Well Integrity Policy clear? Does it safeguard HS&E? Is it endorsed at a senior level?	The Well Operator should have a policy (or other documents that clearly achieve the same aim as a policy) defining its commitments and obligations to safeguard health, environment, assets and reputation by establishing and preserving well integrity. This well integrity policy shall be endorsed at a senior level within the Well Operator organisation.	**Evidence should include the document reference to which the information is contained along with the chapter, page and paragraph such that it is easy to trace**
2.	Does the WIMS explain how the Well Integrity Policy will be achieved?	The Well Operator well integrity management system (WIMS) should clearly indicate how the policy is interpreted and applied to well integrity.	
Resources, Roles, Responsibilities and Authority Levels;			
3.	Are roles and responsibilities clearly defined?	Each Well Operator should define the roles and responsibilities for all professional, supervisory, operational and maintenance personnel required to manage the well integrity system. Roles and responsibilities should be documented.	
4.	Does the WIMS reference an appropriate wells personnel competency system?	Each Well Operator should ensure that their personnel (employees and contractors) who participate in well integrity activities are competent to perform the tasks assigned to them. Each Well Operator should define well integrity personnel competency requirements to ensure that well integrity activities are carried out in a manner which is both safe and efficient as regards protection of health, the environment and assets. A competence performance record should be maintained that demonstrates compliance.	
Risk Assessment Aspects of Well Integrity Management;			

5.	Is there an established procedure for wells risk assessments or is a corporate risk assessment used?	The risk assessment procedure chosen should be suitable and sufficient for wells matters. Where a separate wells specific procedure is used it should be aligned to and reference the corporate risk assessment procedures.	
6.	Is the risk assessment matrix suitable for MAH wells risks?	The Well Operator should determine appropriate levels/definitions for consequence (severity) and likelihood of occurrence (probability) categories on the risk assessment matrix axes.	
Well Barriers;			
7.	Have the barriers for each well type been documented? Are these sufficiently detailed and suitable for downhole conditions?	The Well Operator should define a barrier philosophy for each of the well types within the WIMS. Typically this will require two barriers in the direction of flow. Where two barriers are not achieved an ALARP demonstration may be required.	
8.	Does the WIMS mandate a risk assessment where a well is outside original design specification? How should this be documented?	In cases where a barrier envelope cannot be maintained according to the original design specification, the Well Operator should perform a risk assessment to establish the required controls to mitigate the risk. This risk assessment is likely to be included in a formal Management of Change process.	
9.	Does the well operator use well barrier schematics to demonstrate the design barriers or capture current well barrier status? If not is the solution they employ equally effective?	Well barrier schematics as mandated by NORSOK D10 are effective. ISO 16530-1 also states that well barrier schematic should be used. In some cases, other methods such as spreadsheets tables may be used where they are equally effective.	
Well Component Performance Standards;			
10.	Are performance standards in place for each type of well? Do they detail the requirements for	The Well Operator should define performance standards for each well type. Performance standards, supported by the risk assessment, are the basis for the	

	maintenance, assurance and verification activities? Are the company standards sufficiently detailed and refer to appropriate industry standards?	development of maintenance and monitoring requirements	
11.	Have acceptable leak rates been determined and documented for each well component?	Using a risk-based approach, the Well Operator should define their acceptable leak rates and testing frequency for individual barrier elements for all well types within the acceptance criteria described below.	
12.	Are these contained within a matrix?	Has the well operator defined leak rates for individual well components in a leak rate matrix? If not have equally effective measures been identified?	
13.	How do leak rates compare with ISO minimums and other industry norms?	ISO Acceptable leak rates shall satisfy at least all the following acceptance criteria: · leak across a valve, leak contained within the envelope or flow path: ISO 10417:2004 & API 6AV2 · leak across a barrier envelope, conduit to conduit: not permitted unless the receiving conduit is able to withstand the potential newly imposed load and fluid composition · no leak rate from conduit to conduit exceeding the leak rate specified in ISO 10417:2004, which defines an acceptable leak rate as 24 l/h of liquid or 25.4 m^3/h (900 scf/h) of gas · no unplanned or uncontrolled leak of wellbore effluents to the surface or subsurface environment. ISO goes on to recommend a maximum leak rate for tree valves at 3cc/min/inch. This is consistent with other international standards.	

		Within the UKCS a number of operators apply a liquid leak rate of 2cc/min/inch as their leak rate acceptance criteria, with any leakage above 50cc/min indicating washout. This is significantly below API 14B of 400cc/minute. Where an operator has determined an acceptable leak rate for valves above the 2cc/min/inch value they may be asked to demonstrate why that approach has been deemed ALARP.	
Well Operating Limits			
14.	How are operating limits identified initially and when changes to the well occur?	The Well Operator should identify the operating parameters for each well and clearly specify the operating limits for each parameter.	
15.	How have responsibilities for operating limits been defined and communicated?	The Well Operator should clearly define: · responsibilities for establishing, maintaining, reviewing and approving the well operating limits · how each of the well operating limits parameters should be monitored and recorded during periods when the well is operational, shut-in or suspended · life-cycle of the well · requirements for any threshold settings for the well operating limits · actions that should be taken in the event a well operating parameter is approaching its defined threshold · actions, notifications and investigations required if well operating limits thresholds are exceeded · safety systems that are necessary for assurance of operating limits.	
Well Monitoring and Surveillance;			
16.	Does the WIMS include a program to monitor annulus pressures that extend to	The Well Operator should have in place a program to monitor the annuli pressure. To effectively monitor annulus pressures, the following should be recorded:	

	monitoring and trending fluids and pressures?	· fluid types and volumes added to, or removed from, the annulus · fluid types, and their characteristics, in the annulus (including fluid density) · monitoring and trending of pressures · calibration and function checks of the monitoring equipment · operational changes.	
17.	Are valid MAASPs available for all wells and documented sufficiently?	The MAASP should be determined for each annulus of the well. The MAASP calculation shall be documented together with the applied design factors	
Annular Pressure Management;			
18.	Is annulus pressure management across the lifecycle of the well clearly documented?	The Well Operator should manage the annuli pressures such that well integrity is maintained throughout the complete well life cycle. At a minimum, it is necessary to consider the following when managing annulus pressure based upon a risk assessment: · pressure sources · monitoring, including trends · annulus contents, fluid type and volume · operating limits, including pressure limits, allowable rates of pressure change · failure modes · pressure safety and relief systems.	
19.	Is the process for annulus review adequately described?	The Well Operator should define the process of annulus review (investigation) when the operating conditions indicate that the pressure is sustained or a leak in a well barrier envelope has occurred. When such a review is required, it shall be defined and may be based on established criteria for:	

		· frequency of annulus pressure bleed-down or top-ups · abnormal pressure trends (indicating leaks to/from an annulus) · volume of annulus bleed-down or top-ups · type of fluid used or recovered (oil/gas/mud) · pressure excursions above MAASP and/or upper threshold.	
Well Handover;			
20.	Are the requirements for well handover sufficiently detailed?	The Well Operator should include the following in the well handover documentation in the initial handover from the construction to operation phases: · schematic of the Christmas tree and wellhead providing, at a minimum, a description of the valves, their operating and test criteria (performance standards), test records and their status (open or closed) · SSSV status, performance standard and test records · status of ESD and actuator systems · well start-up procedures detailing production/injection rates, as well as associated pressures and temperatures · details of any well barrier elements left in the well (crown plugs, check valves or similar) or devices that ordinarily would be required to be removed to allow well production and/or monitoring · detailed description and diagram of the well barrier envelopes, clearly indicating both primary and secondary well barrier envelopes; detailed wellbore schematic and test records (depicting all casing strings complete with sizes, metallurgy, thread	

		types and centralizers as well as fluid weights, cement placement, reservoirs and perforating details) · detailed completion tally as-installed (listing all component ODs, IDs, lengths, metallurgy, threads, depths) · wellhead and Christmas tree stack-up diagram (general assembly drawing with dimensions) with a bill of materials · wellbore trajectory with the wellhead surface geographical coordinates · pressures, volumes and types of fluids left in the annuli, wellbore and tubing and Christmas tree · well operating limits · subsea control system status and test records (if applicable). Are operational handovers equally well defined?	
Well Maintenance;			
21.	Have you defined and documented maintenance schedules and frequencies?	The Well Operator should define and document the schedules and frequencies for maintenance activities. A risk-based approach can be used to define the frequency and an assessment matrix can be used in the process. The frequency may be adjusted if it is found that the ratio of preventive/corrective maintenance tasks is very high or very low once sufficient historical data have been obtained that establish clearly observable trends.	
22.	Does your maintenance management system capture the operating limits and OEM	Well equipment that is part of a barrier element should be maintained using parts that retain the current operating limits. Replacement parts should be from the	

	requirements for selection of spare parts for wells? How are deviations from this practice captured?	original equipment manufacturer (OEM), or an OEM-approved manufacturer. Deviation from this practice should be clearly documented and justified.	
Well Integrity Failure Management;			
23.	Is there a process for the management of risk in relation to well barrier failures, performance failures, etc.?	The Well Operator should establish a well anomaly process that describes the management of risks associated with failure(s) of a well barrier envelope or well barrier element(s) against their performance standards, as defined by the Well Operator, legislation or industry standard.	
24.	Is there a dispensation process to manage wells risks?	The Well Operator should apply a dispensation process that assesses and manages the risk(s) that apply to temporary non-compliance to the well integrity management system.	
Management of Change			
25.	Does the WIMS clearly reference a formal MOC procedure that is suitable for both permanent and temporary changes?	The Well Operator should apply a management of change (MOC) process to address and record changes to integrity assurance requirements for an individual well or to the well integrity management system.	
26.	What key process steps does your MOC contain?	The MOC should include the following process steps: · Identify a requirement for change · Identify the impact of the change and the key stake holders involved. This includes identifying what standards, procedures; work practices, process systems, drawings, etc. would be impacted by the change · Perform an appropriate level of risk assessment in accordance with the Well Operator risk assessment process. This would include; o identifying the change in risk level(s) via use of a risk assessment matrix or other	

		means ○ identify additional preventative and mitigating systems that can be applied to reduce the risk level ○ identify the residual risk of implementing the change/deviation ○ review the residual risk level against the Well Operator risk tolerability/ALARP acceptance criteria. · Submit MOC proposal for review and approval in accordance with the Well Operator authority system · Submit relevant MOC to Well Examiner · Communicate and record the approved MOC. · Implement the approved MOC · At the end of the approved MOC validity period, the MOC is withdrawn, or an extension is submitted for review and approval · ICP is involved as appropriate	

Appendix 3: Inspection Guidance – Role Specific Interview Outline

Role specific interviews with key personnel who monitor and manage well integrity during the operate phase of the well lifecycle should be interviewed. Consideration should be given to the location of these interviews as certain personnel may benefit from access to internal company computer systems to demonstrate the particular systems employed for the management of well integrity.

At least one of each of the following roles within the well operator's organisation should be interviewed:

- Production Engineer; usually responsible for collating the well integrity data.
- Well Integrity Engineer; responsible for the day to day collation, monitoring analysis and reporting.
- Well Integrity TA responsible for review and approval of well integrity deviation/dispensations.
- Person responsible for the overall well integrity of the well operator's UK well stock.
- OFFSHORE – production operator, control room operator, production supervisor as applicable.

It is anticipated that the role specific interviews can be completed within 1 full day of inspection onshore (with a potential offshore interview as part of any planned offshore inspection or investigation) with the following indicative agenda:

Anticipated Start Time: 08.30 am

a.	Introductions, HSE setting the scene, Well Operator may wish to present an overview to HSE of their Well Integrity Management System	0830-0930 hrs
b.	Interview with Production Engineer	0930-1000 hrs
c.	Intervention with Well Integrity Engineer	1000-1030 hrs
d.	Interview with Well Integrity TA	1045-1200 hrs

Lunch Break

e.	Interview Responsible Person (Well Integrity)	12:45-1400 hrs
f.	Inspector consolidation or time for interviewing additional positions as identified by Well Operator.	1400 -1430 hrs
g.	Closeout Meeting	1430-1530 hrs

Appendix 4: Inspection Guidance – Role Specific Questionnaires

RESPONSIBLE PERSON Name:_______________________________ Position:_______________________________

	Questions	Model Answer	Evidence and Comments
Well Integrity Policy and Strategy			
1	How do you implement the well integrity policy across your company, installations and/ or assets?	The Well Operator should define the high level strategic measures to which it is committing in order to achieve the requirements of the asset (well) integrity policy. (the level of this strategy is likely to be: business plans and priorities, resourcing plans, and budgeting)	**To be populated by wells inspector with the answers to the questions given by the interviewed person and compared to previously submitted documents.**
Resources, Roles, Responsibilities and Authority Levels			
2	How do you ensure that you have sufficient resources to manage well integrity?	Each Well Operator should ensure that sufficient resources in their organizations are available to manage well integrity effectively during the operational life cycle of the well for each well in the inventory	
Risk Assessment Aspects of Well Integrity Management			
3	Has base line risk for each well or well type been considered? When was base line risk last reviewed?	This may well be QRA work including the development of bowties. Where appropriate this will be documented in the installation safety case.	
Well Barriers			
4	What factors are taken into account when re-evaluating operating conditions?	During the operating phase of a well, boundary conditions or well usage may change. This requires a re-evaluation of the barrier envelopes and the well operating limits. A well barrier envelope should: · withstand the maximum anticipated differential pressures to which it can be subjected;	

		· be leak and function-tested, or verified by other methods; · Function as intended in the environment (pressures, temperature, fluids, and mechanical stresses) that can be encountered throughout its entire life cycle.	
5	Demonstrate how to access key well barrier status within your WIMS for 3 different categories of well. (for example a platform producer, a subsea producer and a partially abandoned (suspended) well.	Well barrier element: For a well barrier element to be considered operational, it should be verified and maintained through regular testing and maintenance. The location and integrity status of each well barrier element should be known at all times. The Well Operator shall be able to demonstrate the status of well barrier envelopes for each well and well type	
Well Component Performance Standards			
6	How does the well integrity management system interface with management of the emergency shut down systems?	ESD/related safety systems - Performance requirements for emergency shutdown system should be developed with consideration of ISO 10418 and API RP 14C. In addition to the requirements of API STD 6AV2, the Well Operator should define the cause and effects matrix for the emergency shutdown system.	
7	How is wells performance recorded alongside ESD performance data?	Information about valve performance such as leak rates are likely to be recorded within well integrity records, however closure times may be recorded elsewhere. The overall performance of the ESD system should be collated to ensure it achieves the performance standards. The mechanism for sharing this information should be contained within the WIMS.	
Well Operating Limits			
8	How do you assure yourself that	The well should not be operated outside of the	

	the wells have been operated within the limits set within the WIMS.	operating limits. The system should have a mechanism for tracking instances of operating outside limits.	
9	Does the WIMS require action to restore the integrity of an impaired well?	The Well Operator should establish a time bound plan that identifies restoration to production, injection, suspension or abandonment of the identified wells, which is in accordance with the WIMS to mitigate the risk of loss of containment.	
10	Do you have criteria to trigger a formal end-of-well-life review?	The Well Operator should define the end of well life and establish a formal end-of-well-life review process. The end of well life triggers the review that assesses the well status for safe continuation. If the well assessment demonstrates that the well is unsafe for continued use, the Well Operator shall plan either to rectify the well condition or plan for suspension or abandonment. The period by which a well's life can be extended is determined on a case-by-case basis.	
Well Monitoring and Surveillance			
11	How are monitoring and surveillance requirements derived? Where are these documented?	The Well Operator should define the monitoring and surveillance requirements to ensure that wells are operated within their envelope. The Well Operator should determine the frequency of monitoring and surveillance, based on the risk and consequence of breaching the barrier envelopes and the ability to respond. The Well Operator should define and document the schedule, frequency and type of monitoring and surveillance required.	
12	How do these differ for shut-in wells?	A shut-in well is a well with one or more valve(s) closed in the direction of flow. A shut-in well should be monitored according to a risk-based schedule defined by the Well Operator, with due consideration of the risk profile brought about by the change in flow and non-	

		flow wetted components.	
13.	Have you a documented review process for wells not currently producing?	A well should not remain a shut in or suspended or abandoned to phase 1 or phase 2 indefinitely. The Well Operator should establish a periodic review process for these wells that documents and details the intended plan for the well, which may include its permanent abandonment.	
Annular Pressure Management			
14.	What criteria are used in annulus pressure risk assessments?	The Well Operator should assess the risks associated with a sustained annulus pressure. Such risks are related to: · flow capability of any annuli with respect to a loss of containment · annular gas mass storage effect (i.e. volume of gas between the annulus's liquid level and surface) · introduction of corrosive fluids into an annulus not designed to resist such fluids · maximum potential pressure that can occur should the compromised barrier degrade further. The review should focus around the following elements: · source of the sustained annulus pressure based on sample and finger-print results compared to original mud logging data; · source fluid composition and pore pressure; · flow path from the source to the annulus (or vice versa) under review; · leak rate, potential volumes and density changes in the annulus; · condition of the well (remaining life); · content of the annulus and liquid levels;	

		· casing shoe strength changes.	
15.	What criteria were considered when developing annulus pressure bleed down procedures?	Annulus depressurisation or 'bleed down' may be required to maintain the annulus pressure below the upper operating pressure limit. Annulus pressure management procedures should clearly define the constraints of depressurisation and consider the following: · minimizing the number of bleed downs and volume of fluids bled off to limit flow erosion and degradation of leak paths · bleed down sequence should be identified to minimise the risk of casing collapse · bleed downs may introduce fluids into an annulus that could accelerate corrosion or erosion of casing strings · bleeding off liquids which are replaced by gas or lighter liquids can result in higher annulus pressure and increased hydrocarbon mass in the annulus · the risk of hydrate formation during bleed off of hydrocarbon gas should be addressed · contingency plans should be in place to manage annulus pressure during shut downs when bleed off facilities may not be available.	
Well Handover			
16.	What are the requirements for well handover? How are these documented for the different handovers that occur over the well lifecycle?	The Well Operator should verify the well operating limits within the well handover process. The process shall define, as a minimum, the following phases at which well handover typically occurs: · well construction to production operations · production operations to maintenance, intervention or servicing, and back to production operations · production operations to abandonment.	

17.	Are handover forms completed in full or do the parties involved only complete the information that they think is relevant? In these cases how are handover forms verified?	Handovers during the well lifecycle should include only those items that are appropriate, and capture any changes in the well's configuration or operating limits.	
18.	How do you identify the appropriate personnel for the handover operation? How is their competence for this process verified?	The Well Operator should nominate competent personnel who are responsible for preparing, verifying and accepting the well handover documentation. These persons should sign and date the documentation accordingly.	
Well Maintenance			
19.	Have all relevant well components been identified within the maintenance management system?	The Well Operator should identify all respective fitted components in a planned maintenance program. These would typically include, but are not limited to, the following components: · wellhead, tubing hanger and Christmas tree, including all valves, bonnets, flanges, (tie-down) bolts and clamps, grease nipples, test ports, control line exits · monitoring systems, including gauges, transducers, sand detectors, corrosion probes etc.) · annulus pressures and fluid levels · down-hole valves (SCSSV, SSCSV, ASV, gas-lift valves) · ESD systems (detectors, ESD panels, fusible plugs) · chemical injection systems.	
20.	What is the current status of wells maintenance across the asset company? Is there a backlog? How is this managed?	The Well Operator should have preventative and corrective maintenance management system for performing well maintenance work, including acceptance criteria, and should keep auditable records of maintenance activities. When defining schedules	

		and test frequencies the Well Operator should take into account the following, as a minimum: · original equipment manufacturer specifications · risk to environment and personnel exposure · applicable industry recognized standards, practices and guidelines · Well Operator relevant policies and procedures.	
21.	What industry standard is used for function and performance testing of ESD/ SSVs?	Function and performance testing of ESD/SSV valves should be carried out as per a defined standard: • API STD6AV2 • ISO 10417 / API14B Further standards and guidance available in Oil & Gas UK Well Lifecycle Integrity Guidelines	
Well Integrity Failure Management			
22.	Is the well integrity failure management process clearly defined such that it can be followed through for any particular scenario?	The process should describe the course of action to correct the failure, based on the number of barrier or barrier elements that remain functional. That is, the level of redundancy of barriers or barrier elements of the well.	
23.	In the event of a well integrity failure how is the initial risk assessment captured?	A well integrity failure should be risk-assessed against the criticality of the failed barrier element, taking into account the redundancies in place and/or any consequential risk to secondary barriers. This may be displayed in a Corrective Action Matrix.	
24.	Does that process set a priority to repair?	The priority-to-repair (response time) should be set in accordance with the risk exposure.	
25.	Do you have a risk-based repair model to provide guidance for remediation? Does the model consider well type, barrier integrity, multiple failures, time-	The Well Operator should have a risk-based repair model and structure in place that provides guidance for adequate resources, such as spares, tools, contracts, etc., in order to meet the response time to affect repairs as defined in the model. The well integrity	

	based actions?	response model should include, but is not be limited to: · well type identification based on risk · single barrier element failures · multiple barrier element failures · time-based course of action.	
26.	How do asset managers and senior management get informed about well status?	Asset managers and senior managers should have on-going visibility of Well Integrity Status, and overdue wells maintenance should use corporate mechanisms such as backlog and deferral procedures.	
Management of Change			
27.	Is there a dispensation process to manage wells risks?	The Well Operator should apply a dispensation process that assesses and manages the risk(s) that apply to temporary non-compliance to the well integrity management system. This process should identify when ICP involvement is required.	
28.	Are dispensations time bound? Is there escalation for re-issue/ extension of dispensation?	Dispensations should be time bound and, if extended, the approval process may escalate in approval level within the Well Operator organisation	
29.	Does the dispensation procedure describe the process of approvals, approval levels, and trigger review of regulator notifications?	The Well Operator should have a procedure that clearly specifies the process and approvals required for deviation from the standard.	
Well Records and Well Integrity Reporting			
30.	Are wells covered by an established document control procedure that is fit for purpose?	At a minimum, the Well Operator shall: · maintain a repository, providing access to data and documents for all relevant users · develop a documented process and procedure for controlling and updating data and documents · establish a data/document maintenance feature to combat degradation and ensure software (where used) inter-changeability	

		· define and staff functions responsible for data collection and document management · define those who are authorized to have access to the records · define how long records are retained.	
31.	Does the WIMS sufficiently document reporting requirements in relation to well integrity?	The Well Operator should define the minimum reporting requirements to effectively reflect the application of the WIMS and all its elements. These may include: · routine reports issued on a predefined periodic basis (e.g. monthly, quarterly, or annually) reflecting the well integrity activities and issues addressed · reporting on the identified KPIs · event-specific well integrity incident and WIMS non-compliance reports and investigations · WIMS audit reports · reporting to the OSDR/ HSE · it should explain how the well integrity status is communicated within the company including to asset and senior managers	
32.	Are report scope and key recipients / signatories of those reports clearly documented?	The WIMS should define the scope, recipients and acknowledgement of receipt of all such reports. Topics covered in the reports may include the following, but is not limited to: · previous well reviews, or ad hoc well reviews · changes to the original boundary conditions · change in the well's function · changes in the well fluid composition · change or possible degradation of well and well	

		related hardware · examination of MOC notices · examination of well deviations issued · well barriers · well integrity issues · scale or corrosion issues · wear and tear to hardware and equipment · accidental damage to hardware and equipment · equipment obsolescence · loss of barrier or containment · environmentally related changes · statutory or legislative changes · changes in local procedures and standards · changes to the local operating risk model · advances in technology that may be implemented · changes to the operating limits of equipment/material, e.g. latest manufacturer's bulletins or industry standards · repairs to, and replacements of, well components, form valve parts to complete work over · relevant equipment maintenance information in order to improve equipment technical specifications, reliability data and/or preventive maintenance intervals.	
Performance Monitoring of Well Integrity Management Systems			
33.	Do you conduct WIMS performance reviews across your well stock?	The Well Operator should conduct performance reviews to assess the application of the WIMS to a defined well stock. The primary objectives of a performance review are to: · assess how well the WIMS is performing in accordance with its objectives;	

		· assess how well the WIMS processes adhere to the policies, procedures and standards defined in the WIMS; · identify areas of improvement. Where areas for improvement are identified, any changes required to address these improvements should be specified and implemented. Implementation of any changes shall follow the risk assessment and management of change processes.	
34.	What frequency?	Such reviews should be performed at a defined frequency as determined by the Well Operator based upon associated risks.	
35.	What additional triggers are there for a review of the WIMS?	In addition, ad hoc reviews should be performed as and when deemed necessary when new information becomes available that can have a significant impact on well integrity risk or assurance processes.	
36.	Who performs the reviews?	The review should be performed by a group of personnel who are deemed competent in well integrity management and who are familiar with the Well Operator WIMS. It is recommended that, where practicable, at least some personnel involved in the reviews should not be directly involved in well integrity management of the well stock under review, in order to provide a broader perspective and to aid in identifying any issues that can have been overlooked by those who are engaged in day-to-day operation of the wells under review.	
37.	What wells KPIs have been identified and how are these tracked and reported?	The Well Operator should determine KPIs and a suitable review frequency that are appropriate to track the effectiveness of their particular WIMS. These should normally be based on metrics that are aligned	

		to critical objectives of the WIMS.	
Compliance Audit			
38.	Do you audit the WIMS? Is compliance monitoring in place?	The Well Operator should establish an audit process to demonstrate compliance with the well integrity management system. The audit reports should provide clear indications as to which sections of the WIMS are functioning adequately, and which sections need further action.	
39.	Are audit frequencies, terms of reference, objectives and scope identified?	Each element of the WIMS should be the subject of an audit. The Well Operator shall establish the frequency of audits. Each audit should have clearly defined terms of reference focused on testing compliance with the WIMS and the effectiveness of meeting the objectives of the WIMS. The audit objectives, scope and criteria have to be agreed in advance.	

TECHNICAL AUTHORITY Name:______________________________ Position:______________________________

	Questions	Model Answer	Evidence and Comments
Well Barriers			
1.	How do you maintain an up to date status of your well barriers?	The Well Operator should know the status of each well barrier envelope and shall maintain all well barrier envelope(s) according to the well's intended well operating limits.	To be populated by wells inspector with the answers to the questions given by the interviewed person and compared to previously submitted documents.
2.	Do you monitor the integrity parameters to identify degradation?	Do you monitor test results that may indicate a trend towards failure, such as valves that require functioning or greasing to achieve a good test, or where, although within the acceptance criteria the leak rate of a valve is increasing over time.	
Well Component Performance Standards			
3.	Have you had occasion recently where a well barrier has failed to meet its performance standard? Please describe how this was addressed including providing the risk assessment.	In the case of one or more barrier impairment(s) the Well Operator should risk assess the potential loss of containment and put mitigating controls in place as deemed necessary by the assessment. Operating outside a defined envelope should be managed by a formal risk based dispensation system.	
4.	Does the WIMS system provide guidance on pressure testing requirements such as flow direction? Is this incorporated in individual test procedures and acceptance criteria?	A component should be tested in the direction of flow. If this is impossible or impractical, a test of the component in the counter-flow direction should be performed where possible. The test can be of limited value in establishing the component's ability to seal in the direction of flow. Any component tested in the counter flow direction should have this documented.	
5.	Do you have any plugs dressed with chevron seals (unidirectional)? How are testing requirements documented?	Plugs dressed with chevron seals (or 'V' packing), or valves with separate sealing faces, should be considered uni-directional. They should be tested in the direction of flow to be considered a barrier.	

6.	Do you require Double Block and Bleed (DBB) isolations for breaking well containment?	In the case of an in-line valve that requires maintenance or repair, there can be pressure sources both upstream and downstream to consider when isolating the valve in preparation for breaking containment. A double block-and-bleed or two barrier principle should be applied for upstream or downstream isolation.	
Well Operating Limits			
7.	Is it possible to trace current well operating limits to the original specifications and designs from which they were derived?	The well operating limits should be based on the specifications of the components that make up the well with their design factors and performance standards applied.	
8.	What would trigger a review of a well's operating limits?	Any changes in well configuration, condition, life cycle phase or status requires the well operating limits to be checked and potentially updated.	
9.	What aspects are covered within the well operating limits?	Well operating limits may include (as applicable): · wellhead/tubing head production and injection pressure · production/injection flow rates · annulus pressures (MAASP) · annulus bleed-offs and top-ups · production/injection fluid corrosive composition (e.g. H2S, CO2, etc. limitations) · production/injection fluid erosion (e.g. sand content and velocity limits) · water cuts and BS&W · operating temperature · reservoir draw-down · artificial lift operating parameters · control line pressure and fluid · chemical injection pressure and fluid	

		· actuator pressures and operating fluids · well kill limitations (e.g. limits on pump pressures and flow rates) · wellhead movement (e.g. wellhead growth due to thermal expansion and wellhead subsidence) · cyclic load limitations leading to fatigue life limits, e.g. risers, conductor casing, thermal wells · allowable bleed-off frequency and total volume, per annulus · naturally occurring radioactive material (NORM) production · corrosion rates; · tubing and casing wall thickness · cathodic protection system.	
10.	Are well and tubing load and tree and wellhead load limits identified?	Well and tubing load, and tree and wellhead load limits should be identified, understood and revisited where necessary throughout the lifecycle of the well.	
11.	Are schematics, other diagrams, wellhead manuals current? Are they controlled documents?	Schematics and installed equipment records should be current. These records should be controlled and updated when well equipment is modified or replaced. Wellhead manuals should be controlled documents.	
Annular Pressure Management			
12.	What alternative methods of integrity verification do you employ where annuli do not maintain a positive pressure?	The well operator should maintain a record of annulus top-ups including frequency and fluid composition where annuli can no longer maintain positive pressure. The situation should be risk assessed and additional methods identified to achieve ALARP.	
13.	What factors have been considered in relation to the frequency of monitoring and surveillance of annuli?	The Well Operator should determine the frequency of monitoring and surveillance. Consideration should be given to the following items when establishing the monitoring frequency:	

		· expected temperature changes and effects, especially during start-up and shut-in · risk of exceeding MAASP or design load limits, risk of sustained annulus pressure · response time for adjusting annulus pressure; · sufficient data for trending and detection of anomalous pressures · deterioration from corrosive fluids (e.g. H_2S and chlorides) · operating characteristics of control/injection lines (e.g. chemical injection lines, size, operating pressure etc.) · annuli used for injection · changing the well function, i.e. from producer to injector, etc. · there is a risk of external casing corrosion as a result of aquifer penetration.	
14.	Is there a controlled procedure for annulus bleed down or pressure build up tests on annuli?	The Well Operator should establish a procedure for conducting the pressure bleed-down/build-up tests. An example of a methodology for performing such tests can be found in API RP 90.	
15.	What factors would trigger recalculation of MAASP?	MAASP should be recalculated if: · there are any changes in well-barrier-elements acceptance criteria · there are any changes in the service type of the well · there are annulus fluid density changes · tubing and/or casing wall thickness loss has occurred · there are changes in reservoir pressures outside the original load case calculation.	

		The differential pressures across tubing, casing, packers and other well equipment should not exceed their respective design load limits	
16.	What is the policy for annulus limit thresholds? How has this been assessed as fit for purpose?	The Well Operator should define upper thresholds. These should typically not exceed 80 % of MAASP of the annulus it is applied on, or exceed 100 % of the MAASP of the adjacent outer annulus. Deviation from this requirement should be risk assessed, mitigated and recorded through MOC with formal technical authority approval	
Wells Maintenance			
17.	Does visual inspection feature on your well maintenance management system? If so what criteria are inspected?	Visual inspection is undertaken to assess the general condition of the surface or mud-line equipment, as well as associated protection around the well. The items included in a visual inspection are, but not limited to: · physical damage to well equipment, barriers, crash frames or trawl deflectors · all connections to the well are secure and intact, e.g. instrumentation and control lines · well cellars are clean and free of debris or fluid, including surface water, build-up · general condition of the well head and Christmas tree: mechanical damage, corrosion, erosion, wear · observation of leaks or bubbles emanating from the Christmas tree or well head, especially from annuli and other cavities that are not tested or monitored by other means. If any leaks or bubbles are observed, an estimate of the flow rate should be made and a plan for containment and repair implemented. For subsea wells, vessels should be alert to any	

		surface signs of leakage, taking into account the type, age and condition of the well. A frequency for visual subsea inspection should be set by the well-operator based on risk assessment. In the absence of any prior history, as a guide, a two year inspection frequency is recommended. This inspection should be undertaken, where possible, at the same time as the well integrity testing, to visually confirm valve status and operation.	
18.	Do the defined maintenance system requirements ensure appropriate testing and assurance of well equipment?	Has appropriate testing and assurance been identified for well equipment considering: · function testing · verification testing · leak testing · inflow testing · pressure testing · gas lift valve function testing	

ONSHORE USER

Name:________________________________ Position:________________________________

	Questions	Model Answer	Evidence and Comments
Well Barriers			
1	What information must be handed over from well operations for new wells and wells that have had an intervention?	Once a well has been constructed and handed over for operation, the number of barrier envelopes will have been determined during the well's design and should be documented through a well handover process.	**To be populated by wells inspector with the answers to the questions given by the interviewed person and compared to previously submitted documents.**
Well Component Technical Performance Requirements			
2	Have start-up and shut-down procedures been developed for ESD, SCSSSVs, SSV, chokes etc. to limit impact on well integrity?	The Well Operator should establish the effective start up and shut down sequencing of the ESD's, SCSSSV's, SSV chokes and additional manual valves as part the well operating procedure. This may be recorded in a Cause and Effects Matrix.	
Well Operating Limits			
3	Where do you find the current well operating limits?	The well operating limits should be presented in a format that is readily available and unambiguous for all personnel involved in operating the well.	
4	What do you do if you see a well is deviating from the defined limits?	Any planned deviation from the approved operating limits should be subject to a management-of-change procedure. This process includes a risk assessment and will record the decision to stop or continue operations.	
Annular Pressure Management			
5	What information is recorded when annuli are bled down?	When pressure is bled from an annulus, the following information should be recorded: · date and time · well, slot number and annulus bled down · time to bleed down · pressure bled down · estimated volume of fluid drained	

		· type of fluid (gas, liquid, mixture) bled off and weight, if possible · if the fluid bled off changes state (e.g. from gas to liquid).	
Compliance Audit			
6	What training have you received in well integrity generally? Have you been trained in your role within the WIMS?	Each Well Operator should define Well Integrity competency requirements for personnel to ensure that well integrity activities are carried out in a manner which is both safe and efficient as regards protection of health, the environment and assets. A competence performance record should be maintained that demonstrates compliance.	

OFFSHORE USER

Name:________________________________ Position:________________________________

	Questions	Expected Answer	Evidence and Comments
Well Integrity Management			
1.	Is the Well Status available and on display for easy reference?	To be populated by wells inspector from WIMS document review and inspection preparation	
2.	Do you know the MAASP values for all the wells? How would you know if MAASPs have changed?		
3.	Is there an Annulus Management Procedure? Can you show the inspector the location of the current version?		
4.	What is the frequency of annulus pressure checks? What method is used?		
5.	Do you compare latest readings from previous ones?		
6.	What do you do if the annulus is close to the MAASP?		
7.	What information is required for well handovers? Where is this documented?		
Managing Impairment			
8.	If you thought there was an issue with a well what would you do? Who would you contact?		
9.	What current well deviations are in place on the installation wells? Does that include tied-back subsea wells? Are these wells		

	non-operated wells? How are these non-operated wells managed? (non-operated wells in this context are where the legal well operatorship remains with another company)		
10.	Can you provide the risk assessments associated with those deviations?		
11.	Are there operational risk assessments (ORAs) in place for wells?		
12.	Are there actions on the production personnel in relation to either the deviations or ORAs? How are these tracked?		
13.	Is it clear from the documentation the time limits and actions that need to be carried out?		
Competency			
14.	Have you had well operations training? For example; bleeding or topping up annuli or for well handovers?		
15.	How is this recorded in your competency system?		
16.	How frequently are you assessed?		
17.	Does your competency system identify safety critical competencies?		

Appendix 5: Risk Assessment Review

This risk assessment review is an optional section to test the wells risk assessment process for compliance with industry best practice and would be completed by the wells inspector following discussions with the well operator. Additional documentation may be requested in the event that this section is applied.

Risk assessment	
Questions	**Evidence / Comment**
Is there a specific wells risk assessment procedure or is a corporate risk assessment mechanism used?	
Does the risk assessment procedure give clear roles and responsibilities for the approval of risk assessments?	
Has base line risk for each well or well type been assessed and documented?	
Does the risk assessment process result in suitable and sufficient assessment of risk from impaired wells? (from sample)	
Does the process require the cumulative risk of multiple failures to be adequately addressed?	
Risk assessment considerations.	

Location
 	
The well location can have a bearing on the risks presented by a well in terms of
· geographical location, e.g. onshore or offshore, urban or remote
· facility/well type, e.g. platform, subsea, manned or unmanned facility/location
· well concentration, e.g. single well, multiple well cluster.
 	
Consideration should be given to the following:
· proximity of the well to workers and the potential effects on worker health and safety of any impairment to a well barrier envelope posed by any anomaly
· proximity of the well to the environment and the potential effects on the environment of any impairment to a well barrier envelope posed by any anomaly
· proximity of the well to other wells and infrastructure and the potential effects on such wells and infrastructure of any impairment to a well barrier envelope posed by any anomaly
· assessment of any compounded risk posed by adjacent wells or infrastructure also having some form of impairment of their own barrier envelopes
· societal impacts of any impairment to the well barrier envelope posed by an anomaly; consideration of such impacts should capture not only health, safety and environmental considerations to society at large, but also any economic impacts to society at large
· ability to access the well in order to
  o monitor its condition
  o perform maintenance
  o perform repairs
· ability to access the area in the vicinity of the well in order to mitigate the effects	

of any potential loss of integrity
- ability and time to drill a relief well, if required.

Outflow potential

The ability of the well fluids to flow to the surface or into an undesirable subsurface location within the wellbore, with or without the aid of artificial lift, potentially has a bearing on the magnitude of the consequences associated with a loss of well integrity.

Consideration should be given to the impacts of the following:

- potential sources and leak-paths for outflow (tubing, annulus, control lines, gas-lift valves)
- outflow medium (from reservoirs and also limited volumes, e.g. gas lift gas);
- failure of other barrier elements
- rates; volumes; pressures; temperatures; duration over which the well is able to sustain flow
- effects from offset wells, e.g. the effect that an offset injection well has on sustaining reservoir, pressure support to a producer to enhance its ability to flow.

Well Effluent

The composition of the well stream has a bearing on the risks posed by any well, both in terms of the effects of well effluent on impairment of the well barrier envelopes, and the health, safety, environmental and societal risks associated with potential discharge of these effluents in the event of a loss of well integrity. The effects of the following fluid components within the well stream composition should be considered in a risk assessment associated with any potential anomaly:

- sour components
- corrosive components
- poisonous components
- carcinogenic components
- flammable or explosive components
- erosive components
- asphyxiating components
- compatibility between components
- formation of emulsion, scale, wax and hydrate deposits.

External Environment

In addition to well integrity risks influenced by outflow potential and well effluents, there are potential well integrity risks posed by exposure of well barriers to external environments that can be unrelated to the production or injection intervals to which these wells are connected. The following effects should be considered:

- external corrosion of structural components such as conductor casing, surface casing and wellhead exposed to the atmosphere (i.e. due exposure to weather)
- external corrosion of structural components such as conductor, surface casing and wellhead exposed to the marine environment
- external corrosion of casing strings exposed to corrosive fluids in subsurface locations (e.g. aquifers containing corrosive fluids, incompatibility between annulus fluid and top up fluid, corrosive top up fluid)
- fatigue of structural components due to cyclic loading (e.g. motion of wellheads, conductors, tieback casing strings, etc. due to the action of waves and currents

offshore, wellhead motion due to interactions between loads imposed by BOPs/risers and wellheads during any drilling or work-over activities)

- impact of cyclic and/or thermal loading of wells on soil strength and the ability of soils to provide structural support to the well
- external loads on wells associated with earth movements (e.g. reservoir compaction, earthquakes, tectonic motion associated with faults and motion of ductile materials such as salt formations)
- mechanical impacts associated with dropped objects (from facilities, vessels, vehicles or other equipment in the proximity of the wells)
- mechanical impacts associated with collisions (e.g. by ships or vehicles).

Redundant Systems

Redundant systems constitute the components within the well that provide additional safeguards to mitigate potential impairments to well barrier envelopes. Consideration should be given to the following when assessing how a redundant system affects well integrity risks:

- extent to which the redundant systems can be operated independently of a system that could be impaired
- response time of redundant systems
- service conditions for which the redundant systems are designed, relative to those of the system that can be impaired
- method of operation of the redundant systems, e.g. manual or automatic.

Examples of redundant systems include an outer annulus (if rated), additional inline valves and additional ESD systems.

Are suitable risk assessment techniques identified?

Identification of the types of well anomaly and failure-related events that are possible for the well(s) that are being assessed:

- determination of the potential consequences of each type of well failure-related event. The consequences can be to health, safety, environmental or societal or a combination of these factors
- determination of the likelihood of occurrence of the event
- determination of the magnitude of the risk of each type of well failure-related event based on the combined effect of consequence and likelihood.

The assessment of any well failure-related event is normally depicted on a risk assessment matrix, such that risk can be categorized or ranked based on the combined effects of consequence and likelihood of occurrence.

A qualitative risk assessment may be used where the determination of both consequence and likelihood of occurrence is largely based on the judgement of qualified and competent personnel based on their experience.

Quantifiable risk assessment (QRA) is another technique that may be applied to assess well integrity risks. This technique also assesses both consequence and probability but uses information from databases on well integrity failures to quantify the probability of a given event occurring.
Failure-mode and effects and criticality analysis (FMECA) can also be used to determine well integrity risks. FMECA is particularly useful in establishing the types of component failures that can occur, the effect on the well barrier envelope(s), and the likelihood of such failures occurring. This information can then be used to assist

design improvements and in establishing the type and frequency of monitoring, surveillance and maintenance required to reduce the risk of the failures modes identified as part of the FMECA.

Application of risk assessment in establishing monitoring, surveillance and maintenance requirements

The determination of appropriate techniques, including the required frequencies at which these techniques are applied, should ideally be supported by an assessment of the well integrity risks.
The risk assessment normally involves a process to identify and rank the risks from potential well failure-related events. The risk assessment is used to help establish:

- types and frequency of monitoring
- types and frequency of surveillance
- types and frequency of maintenance
- appropriate verification test acceptance criteria.

Once these parameters are established, they are used to reduce the risks of the identified potential well failure related events to acceptable levels. There should therefore be a clear linkage between the overall risk profile of any given well type and its monitoring, surveillance, maintenance and acceptance regime. This normally means that wells with higher risks of well failure related events require more frequent maintenance in order to reduce risk.

It is necessary for the Well Operator, when using a risk-based approach, to map for each well type the components that may require monitoring, surveillance and maintenance in a risk based model. One approach is API RP 580; used to identify the magnitude of the risk presented by the failure of a single component (initially assuming no monitoring, surveillance or maintenance) and maps this risk on a risk assessment matrix. Once the risks for all components are mapped on the matrix, isometric lines (i.e. lines plotted on the matrix that represent the same level of risk) can then be used to help define appropriate monitoring, surveillance and maintenance frequencies, together with an acceptance regime for such activities, to mitigate the identified risks.

Application of risk assessment in the assessment of well integrity anomalies

If an anomaly has the potential to affect the defined operating limits of the well, the risks posed by such an anomaly should be assessed and addressed. The Well Operator may already have established the activities that it is necessary to implement in order to address the anomaly based on existing practices or procedures.

The following steps describe the typical process that should be followed to establish the well integrity risk:

- identify the well integrity anomaly
- assess whether the anomaly poses potential risks from well failure-related events or can lead to further anomalies that pose such risks
- assess the consequences and likelihood of each risk
- assess the magnitude of each risk (equal to the product of the consequence and the likelihood) associated with each event, preferably using a risk assessment matrix
- assess what actions or activities can be implemented that mitigate or reduce each risk

- assess the consequence, likelihood and magnitude of each risk after implementation of mitigating actions or activities, preferably using a risk assessment matrix
- assess whether each residual risk (i.e. the magnitude of the risk after any risk mitigation/reduction measures are implemented) is tolerable enough to permit the well to remain operational. The magnitude of risk (prior to implementation of any risk reduction measures) should be used in determining the actions that are appropriate to address the anomaly. Generally, the higher the risk, the greater the priority and/or resources that are required.

Appendix 6: Performance Assessment

The EMM Risk Gap should be judged on the basis of the responses to the inspection questionnaire and hence the Duty Holder's Performance Score according to:

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