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Risk Based Verification of Subsea Blowout Preventer System

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ABSTRACT

An enquiry into the Piper Alpha disaster in 1998 led to a new approach of goal setting safety legislation which forms the framework adopted by offshore regulators especially United Kingdom, to address and manage risks of Major Accident Hazards (MAH). This enhanced the concept of verification in general and Risk Based Verification (RBV) in particular. This paper presents the application of this concept of verification to the Blowout Preventer (BOP) which undoubtedly is the final line of defence against major accident of a blowout in offshore drilling for the management of MAHs. This research begins with a review of current trends in offshore safety regulations, a discussion on the concept of verification principles, benefits and RBV. A RBV framework is proposed for the management of hazards in a blowout preventer system. The BOP system is adequately explained followed by a demonstration of the applicability of proposed framework on the system with major accident hazards and Safety critical elements (SCEs) listed. The blind shear ram was found to be the most critical component i.e. SCE in the BOP system which is very much in line with the requirement for the verification of a shear rams. Finally, both the benefits and the limitations of RBV in offshore applications are highlighted.

Key Words: *Safety Critical Element, Blowout Preventer, Risk Based Verification (RBV).*

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1. INTRODUCTION

Major accidents in the offshore industry like the Alexander L. Kielland, Piper Alpha, Ekofisk B and Montara have often led to a review and revision of practices and regulations with the aim of avoiding similar or major accidents in the future. In early response to Macondo disaster in the Gulf of Mexico, the US Secretary of interior issued recommendations for increased safety measures and a directive [1],[2] with the aim of improving safety in offshore drilling operations. The directive used emergency rule making to cover up gaps in the regulatory regime and defined a number of new prescriptive requirements [3].

The Piper Alpha disaster in 1988 ushered in the Offshore Installation (Safety Case) Regulations introduced in 1993, amended in 1996 to include the verification of safety critical elements (SCEs). The Offshore Installations and Wells (Design and Constructions, etc.) Regulations 1996 (DCRs) were introduced to deal with various stages of the life cycle of installation. These were a direct result of Lord Cullen's recommendation after the Piper Alpha public enquiry [4]. Since then the offshore industry is being directed towards a risk-based goal setting regime which accounts for new types of events, needed innovation and new technologies. In these risk-based goal setting regimes, performance requirements and acceptance criteria are specified and industry must document that their specific solutions meet such requirements in terms of acceptable risks.

The advantage of goal setting or performance-based regulation is that solutions to problems are developed free of specific prescriptions. There is however the challenge of more risk analysis and documentation to be carried out in each individual case to demonstrate to authorities that performance goals have been met. This is where verification plays an important role in maintaining a required level of safety in the life cycle of an asset. It is an independent and systematic examination of the various life cycle phases of an asset to ensure conformity or compliance with some or all of the assets specification. Verification does not necessarily confirm a perfect system or asset but rather helps to identify errors or failures associated with an asset thereby contributing to reducing risks and health and safety of personnel associated with it. Risk-based verification, as the name implies is a structured process using risk and cost-benefit analysis to strike a balance between technical and operational issues and between safety and costs. This provides the ability to focus verification effort where the contribution is cost effective [5].

2. LITERATURE REVIEW

Verification is as a result of the performance-based safety regime where, instead of the regulator imposing rules, it proposes specific assessable goals that asset owners must meet. This gives owners some flexibility in how they will achieve these goals. An important aspect of this safety regime is that the responsibility for managing safety of life, property and damage to the environment now rests on the Duty Holder – who is either the owner or the operator of the asset. Verification is an independent and systematic examination of the various lifecycle phases of an asset to determine if it satisfies the associated performance specification. It compliments routine design, construction, operation and maintenance. It is important to note that verification is not a substitute for the routine processes (i.e. design, construction, operation and maintenance) but rather acts as a third party to confirm compliance of an asset.

The customer or owner has an asset with requirements for which a contractor develops a project and demonstrates compliance. The role of verification is to confirm compliance for which the entire responsibility still rests on the owner or Duty Holder. In the context of the offshore environment, verification of Safety Critical Elements (SCEs) is required to be undertaken by an operator, herein called a Duty Holder, for the life of an asset or installation from design, construction, operation and eventual decommissioning phase. SCEs are established through hazard analysis and risk assessment studies. The main features of risk-based verification include: Reduced probability of undesired events; Cost and time saving; Reduced asset downtime; Improved reliability; Auditable process; Provides confidence to stakeholders [5].

Verification based on risk is founded on the premise that the risk of failure can be assessed in relation to a level that is acceptable and this process can be used to manage that risk. This verification process is therefore a tool to maintain risk below the acceptable limit and is termed Risk Based Verification (RBV). Through this process, work effort and resources can be optimised, leading to improvements in effectiveness. The development of an RBV shall depend on a risk assessment and the findings from examination of quality management systems, documents and production activities. This approach has been used in other high-technology industries such as chemical and aviation sectors for many years. Through the use of a risk-based safety approach, system performance can be improved and it also ensures that new designs and operation strategies are efficient. It can also provide mechanisms for predicting high-risk scenarios with available resources in a cost-effective way [6]. Figure 1 shows the difference between unstructured verification and Risk Based Verification. In RBV, verification efforts are matched against the risk level and this leads to creation of confidence in a cost-effective way.

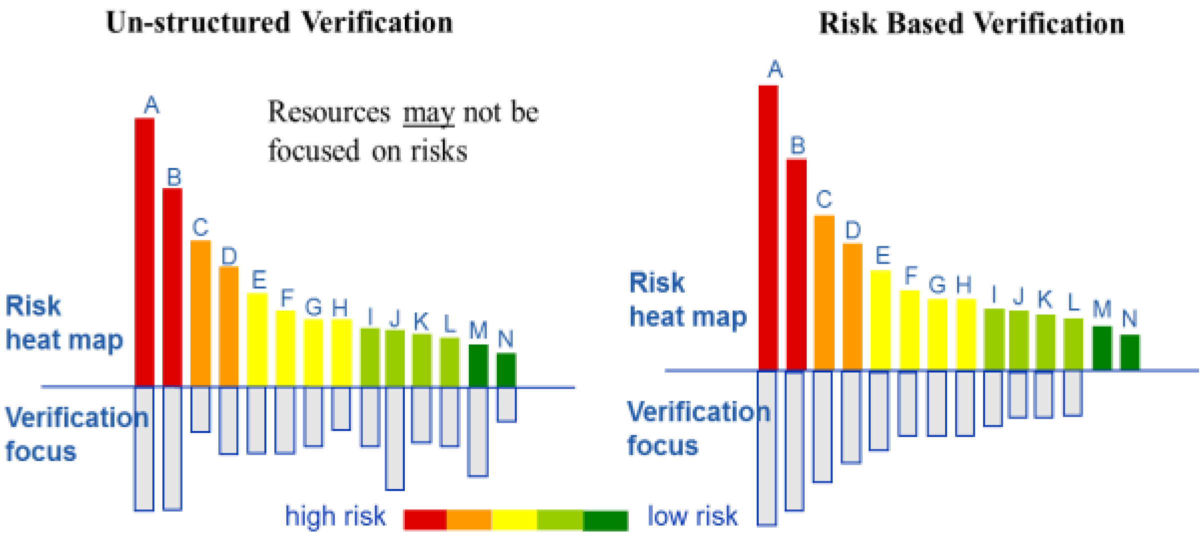

Figure 1: Difference Between Unstructured Verification and RBV (DNV, 2006)

Liquefied Natural Gas (LNG) floating facilities involving process applications have commonly been used onshore but their deployment on floating units in a marine environment presents new risks. [7] applied a novel RBV to review the process solution for a floating LNG production unit with the aim of verifying the performance of the process. The approach adopted was based on the work process used for qualification of new technology, which is widely used for component assembly but had not been commonly employed in the evaluation of process performance. The main steps of the work process were *qualification basis*, *technology assessment*, *threat identification*, *qualification plan development*, *analysis and testing*, *performance assessment* and *technology deployment*. Some of the identified issues and their impact were discussed. The review identified a large number of observations. Efficiency of the review was enhanced by directing attention to key issues and not areas where current knowledge and know-how apply. Though the methodology used was considered to be robust, it could not guarantee that all elements which would not impact on total performance had been identified.

Wang et al. (2012), on the other hand, developed an RBV framework for large offshore systems, demonstrating how it could be applied to a jack-up rig. It incorporated a widely used software package for implementation [6]. The proposed framework addressed identified gaps in literature reviewed by the authors with the introduction of some new features as presented such as; A hierarchical asset definition proposed to allow hazard identification; A step-by-step way of identifying major accident hazards for an offshore asset; A progressive way of identifying SCEs and estimating their criticality; Definition of performance standards, identification of means of performance assurance and identification of means of verification with illustrations.

Marty et al. (2010) used verification activities~~,~~ (independent verification) to help substantiate that current oil and gas best practices are being used, to provide assurance that facilities have been designed to operate safely and to ensure that all HSE risks have been managed to ALARP level [9]. A background on UK legislation prior to the Piper Alpha disaster in 1988 was presented against performance-based legislation introduced as a result of the disaster. This new approach was described and illustrated with its application in the UK Continental Shelf and its evolution in other countries such as UAE and Australia. Key steps supporting UK Safety Case, namely *identification of the major accident hazard*, *strategy for risk reduction*, *identification of Safety critical elements*, *development of Performance Standards*, *Assurance* and *independent verification*, were discussed. Observations were made of contractors and operators engaged in unfamiliar and harsh offshore environments adopting this new approach as a proven method to adequately mitigate risks. The paper highlights regulatory differences and the value of a goal-setting or performance-based process in a Front End Engineering design stage of a project. The author again demonstrates the benefits of performance-based regulation in new environments where the document holder anticipates lack of applicable laws and standards. It concludes with the opinion that introducing the safety and environmental management goals early in the life of an asset or installation will help optimise the decision making around the design, and consider new technologies and best practices to achieve ALARP levels. The implementation of a goal-setting approach is easier when recommended by a regulator but operators can adopt it and ‘self-regulate’ or manage themselves through an Independent Verification Body.

Eriksson et al. (2006) developed a modern risk-based approach to verification and certification of deepwater bundles as offshore developments moves into deep waters with technology that has hitherto been used in shallow waters [10]. The research considered “Flowline towout option for Deep water Subsea Tieback” from a verification point of view. Moving into deeper waters requires a new approach and use of new technical solutions. The risk of applying new technology can be high, but it can also increase the value of the investment if the uncertainties are managed. Traditional verification and certification may not address the key risks related to deep water projects as it has mainly been developed and matured based on risks for traditional shallow to medium water depth installations. The paper was based on the technical requirements given in DNV-OS-F101 “Submarine Pipeline Systems”, ref 1., and followed a risk-based approach as given in DNV-OSS-301 “Certification and Verification of Pipelines”. The authors outlined benefits, described the process of verification and marine warranty and discussed how this applies to deep water bundles. The focus of the article was the selection of verification level. They opined that the level of verification activity should be differentiated according to the risk to the asset or element or phases thereof. If the risk to the asset is higher, the level of verification involvement is higher. Two different ways of selecting the right level of verification, i.e. simplified and detailed, were discussed briefly with basic steps given in each case.

2.1 BOP Safety Assessment Review

Sattler (2013) writes that, following the Macondo incident, BOP systems have been appropriately targeted by regulatory as well as industry standardisation efforts aimed at improvements [11]. The most significant regulatory activity has clearly been in the United States of America. In the area of BOP equipment there has been a formal rewrite of American Petroleum Institute (API) Recommended Practice (RP) 53 “Recommended Practice for Blowout Preventer Equipment for Drilling Wells” into a Standard for the industry, i.e. API S (Standard) 53. This was primarily adopted to provide additional strength to the requirements articulated. New regulations have mandated two main equipment-related verification requirements: well compatibility and shearing of drill pipe. According to Sattler (2013), it is anticipated that additional requirements will include BOP recertification, increased equipment monitoring and specific maintenance requirement. This makes the US regulatory requirement the most stringent in the industry and thus adopted by operators and drilling contractors as current industry practice. One result of these new requirements has been the identification of hitherto unknown deficiencies and increased visibility of unknown weaknesses [11].

From 1983 to 2010, Sintef and ExproSoft have documented results from a number of detailed reliability studies of Blowout Preventer (BOP) systems. The majority of these studies were related to subsea BOP systems[12]. The latest studies involving substantial collection of subsea BOP reliability and kick data were performed on behalf of MMS – Minerals Management Service (now replaced by BSEE – Bureau of Safety and Environmental Enforcement and BOEM – Bureau of Ocean Energy Management). The study was initiated through Sintef, but another study was completed by ExproSoft under subcontract of Sintef (both studies were managed by Per Holand, a renowned researcher in BOP reliability). The study sought to establish an updated reliability overview of deep water subsea BOPs and also to establish a quantified overview of the deep water well kick frequencies and the important parameters contributing to the deep water kick frequency [12].

In a previous study carried out by Holland (2001), operational experience data from deep water subsea BOPs used in the US Gulf of Mexico in 1997 and 1998 were collected and analysed to reveal BOP reliability problems [13]. The results were centred on rig downtime caused by BOP failures, criticality of failures in terms of ability to control a well kick, and BOP subsea test time consumption. These results were compared with corresponding results from previous BOP reliability studies carried out from other areas and time periods revealed no major differences between deep water and normal depths except for increased downtime caused by increased handling time in deep waters. This underscores the need for an effective preventive maintenance scheme when seeking to reduce downtime caused by BOP failures. Baugh et al. (2011) addressed several areas of technology which can be implemented to increase safety on new deep-water drilling BOP systems or retrofitted on current BOP systems in the field [14]. These safety areas include better use of accumulator capacity, greater control over BOP stack functions, more redundancy of control, and improved ability to shear wellbore components. The paper discussed the benefits and noted that the ready availability of these safety upgrades and methods for full BOP subsea operation and control, high volume ROV operations, and shearing drilling collars represent significant upgrades to subsea drilling equipment safety systems post-Macondo.

One other area of interest for the oil and gas industry is the decision on what to do when there are indications of failure within the BOP, especially given that downtime and pulling up the BOP for manual inspection is a very expensive venture. A solution to develop a BOP risk model is proposed by Alme et al. (2012) for the deep water industry [15]. This provides an objective, verifiable decision model allowing owners, well operators and regulators to receive risk-based advice within hours regarding the decision to pull the BOP to the surface or whether the risk levels are acceptable enough to continue operations. The author recommends the modelling of existing BOPs and their submerged control systems in a risk monitor software for simulating operations and visualising results. By this, the industry is able to define the real-time operational risk level the BOP is operating in. The main task of the model is to guide and support oil companies and regulators in the decision process when considering whether to pull the BOP and carry out repairs or if the faulty component is not affecting the operational functionality of the BOP in a negative manner. The major challenges here are related to the ability of fault identification to provide reliable results as this will serve as good input to the overall decision to pull out or not. The implementation of this model should thus be combined with accurate methodologies for fault detection to give the best results for operators and rig owners.

Januarilham (2012) carried out an analysis of component criticality in the BOP system related to the redundancies they have for well shut in, stripping, snubbing and BOP testing operation [16]. To support the analysis, risk assessment tools such as reliability block diagrams, failure mode effect and criticality analysis (FMECA), criticality matrix, redundancy and effect tables were utilised. Due to scarcity of quantitative data, the analysis relied on expert judgement using a qualitative approach. The study identified five most critical components in the BOP. The literature reviewed indicates that there is continuous interest in BOP performance and reliability due to the consequence of its failure. An acceptable management strategy and regulatory regime which ensures that new and inherent hazards are identified and mitigated is what a risk-based verification introduces. Risk-based verification of BOPs boosts owner's confidence that the system remains in compliance with applicable legislation and requirements. It provides owners with a tried and tested lifecycle management process to 'self-regulate'. Based on risk assessment, components with a higher level of criticality will be given more priority.

2.2 Typical Blowout Preventer

The terms blowout preventer, blowout preventer stack and blowout preventer system are commonly used interchangeably to describe an assembly of several stacked blowout preventers of varying types and functions, as well as auxiliary components. A typical subsea deep-water blowout preventer system includes components such as electrical and hydraulic lines, control pods, hydraulic accumulators, test valve, choke and kill lines and valves, riser joint, hydraulic connectors, and a support frame. There are two basic types of blowout preventers (BOPs), ram and annular, which come in a variety of styles, sizes, and pressure rating [17]. A 'BOP stack' comprises several individual blowout preventers serving various functions which are assembled or 'stacked' together, with at least one annular BOP on top of several ram BOPs. These various BOPs can seal around the drill pipe, casing, or tubing, close over an open wellbore, or cut through the drill pipe with steel shearing blades.

In a normal drilling operation, primary well control is achieved by hydrostatic pressure. The weight of the drilling mud counterbalances pressure from the reservoir and prevents hydrocarbons from flowing into the wellbore. Should problems such as poor casing installation or improper mud control disrupt that balance, a well-control event may occur. The BOP stack serves as a secondary means of well control. When a formation influx occurs during drilling, one or more BOPs are activated to seal the annulus, or wellbore, to 'shut in' the well. Denser or heavier mud is then circulated into the wellbore to re-establish primary well control. Mud is pumped down the drill string, up the annulus, out through the choke line at the base of the BOP stack, and then up the high-pressure lines on the riser and through the choke manifold until the down hole pressure is controlled and the influx is circulated out of the well. Once this higher density mud extends from the bottom of the well to the top, the well is back in balance and the integrity of the well re-established for operations to resume [17].

The primary functions of the BOP stack include: Confining well fluid to the wellbore; Providing a means to add fluid to the wellbore; Allowing controlled volumes of fluid to be withdrawn from the wellbore. In the process of performing the above functions, the BOP stack also: Regulates and monitors wellbore pressure; Centralises and hangs off (i.e. closes a set of pipe rams around the drill string and supports its weight) the drill string in the wellbore; Seals the annulus between the drill pipe and the casing to shut in the well; Prevents additional influx from the reservoir into the wellbore; Seals the well by completely closing off the wellbore if no pipe is in the hole; Severs the casing or the drill pipe to seal the well in emergencies (e.g. loss of station keeping/emergency disconnect) [18],[19].

The subsea BOP system is a safety critical system located between the wellhead and the riser. It is designed to assist in well control and to be able to shut in the well in the event of unexpected influx of formation fluids into the wellbore. In addition, the BOP is used for a range of routine operational tasks, such as the testing of casing pressure and formation strength [20]. The different BOP functions are governed by an electro-hydraulic control system called a multiplexed (MUX) control system, consisting of both electrical/electronic and hydraulic components. The control system components are located both topside and subsea. In this section, a detailed description of the BOP control system is presented. Figure 2 gives a simplified overview of the BOP control system. The main topside components of an MUX BOP control system are the control panels and electric/hydraulic supply utilities. Each BOP function must be activated manually by pressing push buttons on the control panels. There are normally two such control panels on a rig floor: the driller's control panel (DCP) and the tool pusher's control panel (PCP), equipped with multiple push-buttons for activation of the different BOP functions. Each of the control panels can be operated on two separate, independent control networks run by two programmable logic control (PLC) solvers. The control panels also display all available information regarding the condition of the BOP system, e.g. flow and pressure levels in the wellbore, accumulator pressure levels and mud volumes pumped.

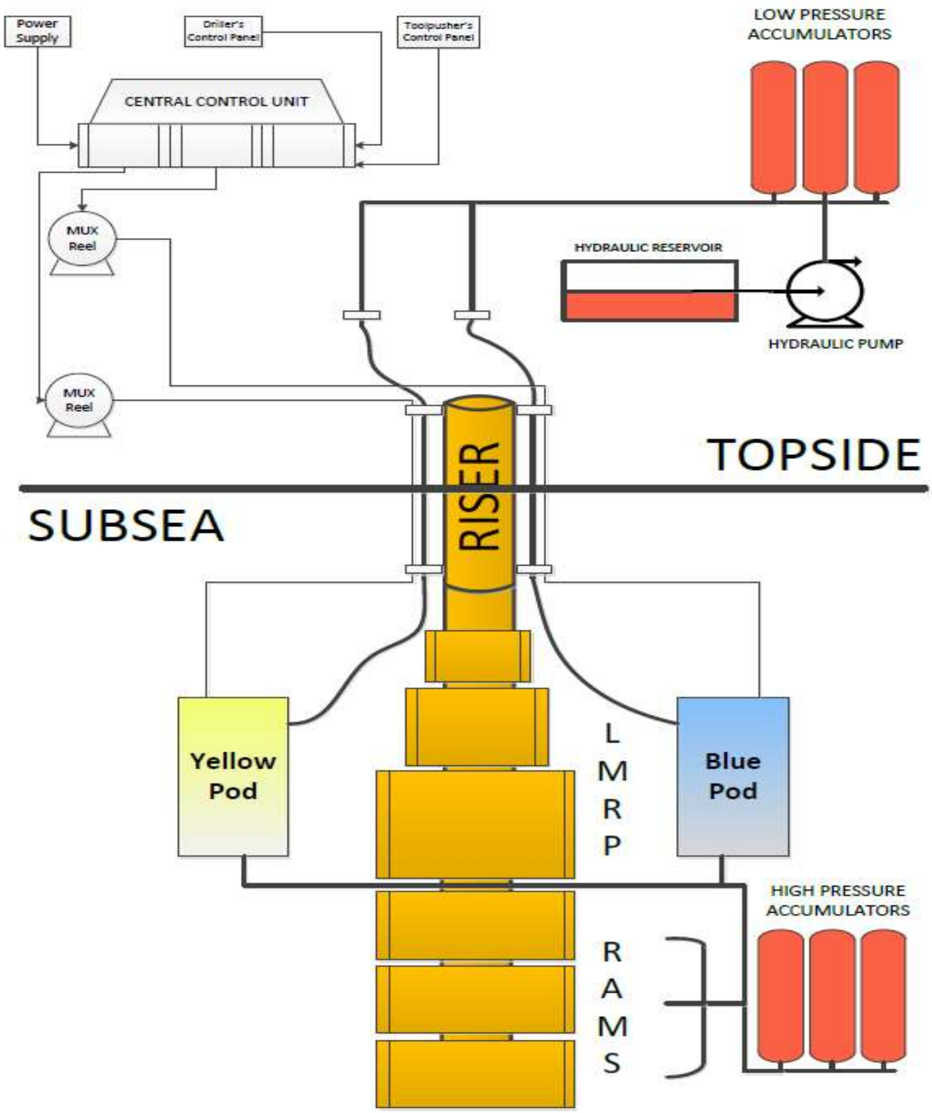

Figure 2: Simplified BOP Control System (Klakegg, 2012)

2.3 BOP Incident – Macondo Incident

On 20th April, 2010 a well control event resulted in hydrocarbons release from the Macondo well in the Gulf of Mexico onto Deepwater Horizon semisubmersible drilling with a catastrophic consequence [21]. The BOP system plays an important role in providing safe working conditions in ultra-deep water regions [4]. The BOP stack for the Deepwater Horizon was located at the wellhead on the seabed, i.e. a subsea BOP. A riser pipe extended from the top of the system to the rig platform, so that drilling fluid could be circulated between the well and the rig. The uppermost of the five rams comprising the BOP stack was a Blind Shear Ram (BSR).

As a last resort in the hierarchy of well-control strategies as discussed above, the two opposing blades of the BSR are designed to shear through the drill pipe and seal the well. At the time of the Macondo blowout, rig personnel could not regain control of the well by using the BOP, because the BSR did not cut the drill pipe and seal the well. The blowout occurred due to the sequential failure of a number of systems, each of which had the capability to prevent the blowout. A critical factor in the causal chain of events that contributed to this accident was the failure of the blowout preventer to isolate the wellbore prior to and after the explosions. Investigations by BP revealed a number of lapses which include the fact that, although the normal mode of BOP operation closed the annular preventer within the expected time, it could not be completely sealed for the next five minutes [20]. The emergency mode of BOP operations involved the operation of the BSR function to shear the drill pipe and seal the well.

High-pressure BSR function and *Emergency Disconnect Sequence (EDS)* functions could not be activated after the explosions as they required at least one operational control pod and an associated multiplex (MUX) cable. The MUX cables had already been rendered inoperable due to the explosions. Both Automatic Mode Function (AMF) buttons, i.e. *AMF* and *Remotely Operated Vehicle (ROV) AMF*, which would automatically close the BSR, were inoperable due to the condition of critical components in the control pods. The last two methods, 'ROV auto shear and ROV hot stab', were both attempted after the rig had sunk but they could still not seal the wellbore. The investigation team identified four areas related to the condition of the BOP system prior to the accident. These were maintenance, control system leakage, testing and modifications. A review of the unit's maintenance records indicated instances of an ineffective maintenance management system. The identified maintenance-related issues had a potential of adversely impacting the performance of the BOP system. On the subject of leakages in the control system, six leakages were noted, two of which could also impact on the performance of the BOP control system.

Records reviewed were not consistent with Transocean's policy which required that all BOP emergency backup systems (defined as EDS, AMF, autoshear, ROV intervention and any other control system) be tested on the surface prior to subsea deployment of the BOP. Daily reports did not indicate AMF and ROV intervention functions were tested on the surface prior to the BOP's deployment on the Macondo well. The investigation team also found nineteen (19) known modifications, some of which had not been adequately documented [20].

3. RISK BASED VERIFICATION METHODOLOGY

Depending on the size and nature of asset being managed, various frameworks have been proposed for verification purposes. These have all involved the basics steps of identifying the safety critical elements, definition of performance standards and list of verification activities to be carried out. For a large offshore system, [6] proposed a framework involving nine steps, as shown in Figure 3 for the RBV process.

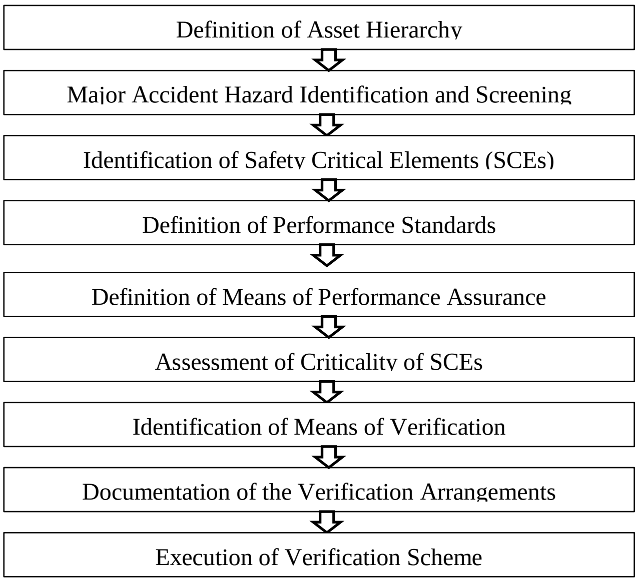

Figure 3: Risk based verification methodology

4. ILLUSTRATIVE CASE STUDY – RISK BASED VERIFICATION ON BOP MODEL (BOP CA408)

This section aims at the proposed RBV methodology approach in the BOP model (BOP CA408) in Figure 4. Considering the large number of critical elements making up the BOP CA408, it is not feasible to demonstrate the described RBV procedure using a whole BOP CA408 system. In light of the above, and in order not to lose generality, a failure modelling is carried out on BOP CA408 to rank the five (5) most critical components and select one for demonstration purposes. A relatively higher breakdown of components is utilised to establish relationships among variables within the system. This illustrative example is presented in parallel with the RBV described to include the overall description herein such as: model system description, major accident hazard identification and screening of BOP CA408, safety critical element identification of BOP CA408, development of BOP CA408 performance standard, assurance of BOP CA408 safety critical component integrity, verification scheme and change management of the whole BOP CA408. It begins with the definition of the BOP model and the RBV proposed framework. The interaction between the Independent Competent Person and the Duty Holder is illustrated through the steps of the proposed RBV methodology.

4.1 System Description – BOP CA408 Subcomponents

The BOP CA408 can be used for subsea drilling activities by semi-submersible drilling rigs. The main elements of this structure are the BOP stack, Lower Marine Riser Package (LMRP) and a hydraulic control system. Other areas considered for risk analysis purpose are the choke valve, kill valve, LMRP connector, wellhead connector and general components inside ram and annular preventers. A control system is a multiplex system of both subsea and surface equipment to control the BOP *C*A408 stack installed on the wellhead at the sea floor. The stack is in two sections: a lower stack connected to the wellhead and a retrievable upper stack, i.e. Lower Marine Riser Package (LMRP), connected to the lower stack. The major subsea units of the BOP CA408 system are the subsea multiplex units, the electro/hydraulic control pods, and the retractable stabs. These units are mounted on the upper stack of the BOP CA408. The principal function of the BOP CA408 serves as a secondary means of well control. When formation influx occurs during drilling it is activated to seal the annulus or wellbore to 'shut in' the well.

The main components of the BOP CA408 stack (S) are as follows: pipe ram (V1), blind shear rams (V2), variable rams (V3), and annular BOP (V4). The components inside the BOP *CA408* ram and preventer include: blind/shear ram seal (V5), piston on both sides (V6), blades on both sides (V7), shear ram housing (V8), annular preventer rubber housing (V9), annular sealing element (V10), and annular piston (V11). The variables in this study are illustrated in Figure 4.

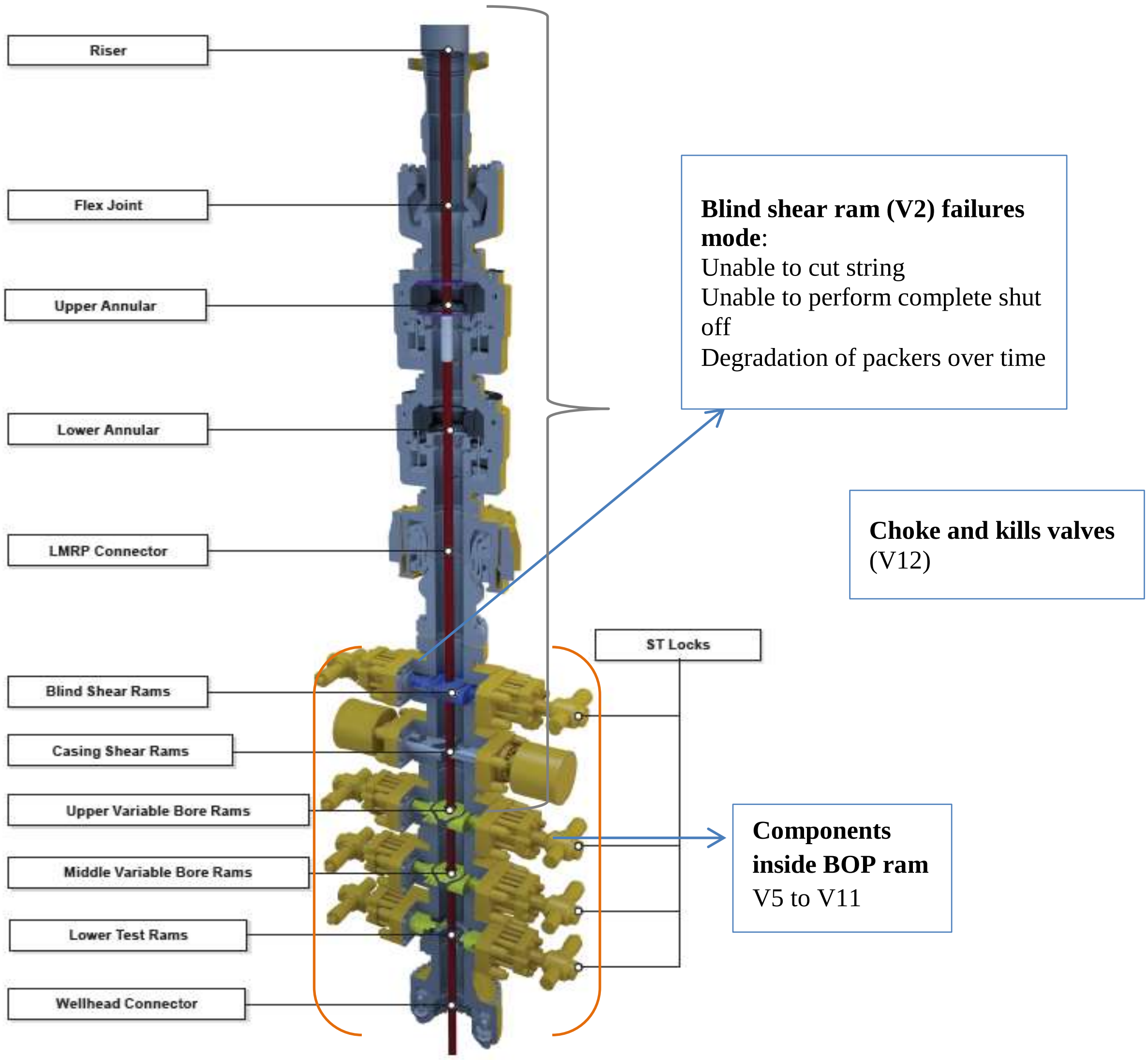

Figure Error! No text of specified style in document.**: BOP CA408 Stack - Blind Shear Ram Description [16]**

The control system (CS) function is to control, operate and monitor the various closing devices of the BOP stack. The main components of the hydraulic BOP CA408 control system are: accumulator bottles (V12), hydraulic line from HPU to BOP (V13), shuttle valve (rams and annular) (V14), fluid reservoir (V15), flange and gasket (V16), master and mini electric panel (V17), pod selector valve (V18), pod mounted accumulator isolation valve (V19), pump in hydraulic manifold (V20), and batteries inside subsea pod (V21). The other components include choke and kill valve (V22) and hydraulic connector (V23). In this illustrative example, the blind shear ram (V2), being within the top six most critical components, is used. Its failure modes include: (a) inability to cut drilling string and seal wellbore, (b) not being able to close or not being able to perform a complete shut off and seal the annulus, (c) degradation of ram packers over time.

The verification philosophy of this system can be identified. In this case study, the verification scheme is organised for the operational stage only. The means of establishing and maintaining all aspects of the installation critical to safety is achieved through a formalised auditable process of safety integrity. The integrity of the BOP CA408 is maintained on a 'live' basis by a formal rigorous integrity assurance process to ensure that the risks to the personnel, the BOP CA408 asset and the environment are maintained at a level that is as low as is reasonably practicable throughout its operating life. The next step highlights the involvement of the Independent Competent Person (ICP) in the process.

4.2 Independent Competent Person and Duty Holder Involvement

The asset owner or Duty Holder in this case study (BOP CA408 owner) appoints an ICP based on the following criteria: (1) recognition of his qualifications and relevant experience relating to safety critical components of BOP CA408, (2) demonstration of his knowledge of goal-setting legislative regime and major hazard management, (3) independence from BOP CA408 duty holder to carry out action surveys, inspection or test of items covered by the verification scheme.

The ICP role in this case study is firstly to review and validate the system description for the identification of major accident hazards. Secondly, he reviews and comments on safety critical components, i.e. SCEs. Thirdly, he provides comments on performance standards established for the components. He carefully and critically scrutinises to determine how BOP CA408 selected components might be in compliance with identified performance standards. Lastly, he keeps the verification under review and provides required remedial actions. The independence of the ICP cannot be overemphasised as it is required for impartial and objective judgement such that the safety of the system is not compromised.

To identify major accident hazards (MAHs), all possible hazard failure modes are first identified within the BOP CA408 system and then a criterion is set to determine the ones that constitute a MAH. The hazard identification technique used in this study is Failure Mode Effect and Criticality Analysis (FMECA). It is a highly structured technique that is usually applied to a complex item of mechanical or electrical equipment. FMECA is used to describe failure modes, failure causes and safeguards of the components as well as giving the description of its effects on other components and the system as a whole. It also describes the level of failure mode occurrence probability (P) and the consequence (C) that might occur should it fail.

FMECA is considered to be a relatively easy way to assess criticality in a system. It could be qualitative in the absence of adequate data utilising expert judgement or quantitative if component failure data exist. A qualitative analysis is used in this work by relying on expert judgement and discussion among other interested parties. The lack of BOP's component failure data and its reduced time input make a qualitative method the best approach for criticality analysis in this research. The failure modes in the analysis are based on the knowledge of experts and are presented only for the most important BOP function.

The probability of occurrence and consequence of failure modes are plotted into the criticality matrix by considering the safeguards to see the critical level of the component. Regarding the ease of using this qualitative FMECA analysis, there are some considerations to take into account. FMECA does not include the relations between components in the system and it assumes that other components function perfectly. It might give a wrong conclusion given that the system fails as a result of components' failure sequence in the system. Furthermore, the assignment of consequence value is based on individual components, which might give inaccurate value of criticality of the system as a whole.

Inputs for the FMECA of the BOP system conducted were obtained from [16] and modified for the purpose of this study based on expert opinion. The BOP *CA408* system is divided into relevant subsystems or main components considering the functions they perform. The identified components are taken through the steps of conducting a FMECA. The main goals of conducting FMECA for BOP CA408 are: To identify failure modes and the resulting effects among variables V1 to V23; To identify how the failure modes can be detected and describe the possible existing provisions and safeguards that prevent the system from failing; To assess the criticality of the failure modes by estimating the probability and severity, and then plot it in the criticality matrix [16].

A list of BOP CA408 components and their corresponding failure modes generated in this study for variables (V1) to (V23) and is presented in Table 1, where C is ranking for consequence of component failure and P is ranking for component failure probability.

Table 1 : List Of Components and Corresponding Failure Modes [16]

ID No.		Item / Functional Identification	Failure Mode	Description	C	P
		BOP stack				
V.1		Pipe ram	F-V.1.1	Not able to close	1	3
			F-V.1.2	Not able to seal around tubular	1	2
			F-V.1.3	Degradation of packers over time	1	3
			F-V.1.4	Internal leakage (leakage through a close	1	2
V.2		Blind shear ram	F-V.2.1	Unable to cut string, thus unable to seal off wellbore	4	3
			F-V.2.2	Not able to close, not able to perform complete shut off and seal the annulus	1	2
			F-V.2.3	Degradation of packers over time	1	3
V.3		Variable bore ram	F-V.3.1	Not able to seal around tubular	1	3
			F-V.3.2	Unable to hold the hang-off weight	1	2
			F-V.3.3	Degradation of packers over time or high	1	3
V.4		Annular BOP	F-V.4.1	Not able to seal around tubular	1	3
			F-V.4.2	Not able to open to full or within 30	1	2
			F-V.4.3	Degradation of elements over time	1	3
		Component inside rams and preventer				
V.5		Blind/shear ram seal (sealing element)	F-V.5.1	Deformed, worn, stiff, eroded	2	1
V.6		Piston on both sides	F-V.6.1	Galling, seizure, misalignment, pitting	3	2
V.7		Blade on both sides	F-V.7.1	Impact failure, brittle failure, pitting, dulling	3	1
V.8		Shear ram housing	F-V.8.1	Deformation, cracking, erosion	3	1
V.9		Annular preventer rubber housing	F-V.9.1	Deformation, worn, stiff, eroded parts	3	3
V.10		Annular sealing element (rubber seal and steel reinforcement segments)	FV.10.1	Deformed, worn, stiff, eroded	3	1
V.11		Annular piston	FV.11.1	Galling, seizure, misalignment, pitting	2	1
		Hydraulic BOP Control System				
V.12		Accumulator bottles	F-V.12.1	Burst bladder	1	3
			F-V.12.2	Leakage through nitrogen 'fill'- system (valve)	1	2
V.13		Hydraulic line from HPU to BOP	F-V.13.1	Leakage, bursting, plugged line	2	3
V.14		Shuttle valve (rams and	F-	Not able to change position	5	1
V.15		Fluid reservoir	F-	Rupture of reservoir	1	4
			F-	Contamination of hydraulic fluid	1	3
			F-	Too low volumetric capacity of reservoir	1	2
V.16		Flange and gasket	FV.16.1	Leakage	2	3
V.17		Master electric panel and electric mini panel	F-V.17.1	Fail to give electric signal for some intended valves and BOP function	1	2
V.18		Pod selector valve	F-V.18.1	Fail to move (change position)	1	2
V.19		Stack-mounted accumulator isolation valve	F-V.19.1	Fail to open/close	1	3
V.20		Pump in hydraulic manifold	F-	Pump does not start, pump not running	1	3
			F-	Pump does not start, pump not running	1	2
			F-	Pump does not stop	1	2
			F-	Pump running but not building up	1	2
			F-	Vibration	1	2
			F-	Pump runs when not intended to run	1	3
V.21		Batteries inside subsea pod	FV.21.1	No voltage	1	2
		Choke valve, kill valve and connector				
V.22		Choke and kill valve	F-V.22.1	External leakage (leakage to environment in main valve or valve connectors)	1	2
V.23		Hydraulic connector	FV.23.1	External leakage	1	2
			F-	Failed to unlock	2	2

To identify what constitutes a major accident hazard leading to the identification of the most critical components of the BOP CA408, a risk matrix is generated by matching the probability of component failure against consequence of component failure, as shown in Figure 5 where colour 'red' represents high risk, 'yellow' medium risk and 'green' low risk.

			Component Failure Probability				
			P = 1	**P = 2**	**P = 3**	**P = 4**	**P = 5**
			Could occur, but never heard of in the world	Has occurred in the world, but very unlikely	Incident has occurred in some operations	Incident has occurred several times in	Incident has occurred several times in
Consequence severity of component failure		Description	< 1/10,000 years	1/10,000 – 1/1000 years	1/1000 – 1/100 years	1/100 – 1/10 years	1/10 – 1 years
	C = 5	30+ fatalities	F-V.14.1				
	C = 4	10-30 fatalities			F-V.2.1,		
	C = 3	1-10 fatalities	F-V.7.1, F-V.8.1, F-V.10.1	F-V.6.1, F-V.1.3,	F-V.9.1		
	C = 2	Serious injury	F-V.5.1, F-V.11.1	F-V.23.2	F-V.13.1, F-V.16.1		
	C = 1	First aid/medical treatment case		F-V.1.2, F-V.1.4, F-V.2.2, F-V.3.2, F-V.4.2, F-V.12.2, F-V.15.3, F-V.17.1, F-V.18.1, F-	F-V.1.1, F-V.1.3, F-V.2.3, F-V.3.1, F-V.3.3, F-V.4.1, F-V.4.3, F-V.12.1, F-V.15.2, F-	F-V.15.1	

Figure 5: Criticality Matrix for BOP System

4.3 Identification of Safety Critical Component of the BOP CA408 System

The matrix of failure modes in red and yellow will be considered critical and, as such, major accident hazards (MAHs). Each individual component in the categories identified is then investigated to see whether its failure would result in the occurrence of any identified MAHs or whether its purpose is to prevent or limit the consequence of any identified MAHs. Such associated MAHs identified and possible consequences caused by the failure of each variable (V1) to V (13) identified in this study are presented using FMECA. The most critical failures are sorted from the highest consequence and probabilities described in Table 2 by calculating the Risk Priority Number (RPN), which in this work will be limited to the product of consequence and probability ranking, i.e. RPN = C x P. The result of the RPN and with comparison to the categories of MAHs and SCEs identified is then mapped in Table 2 for ranking.

Table 2: Prioritisation of BOP Component Criticality from Criticality Matrix (List of SCEs)

Priority	Component	Failure Mode	Description	C	P	RPN
1	Blind shear ram	F-V.2.1	Unable to cut string, thus unable to seal off wellbore	4	3	12
2	Annular preventer rubber housing	F-V.9.1	Deformation, worn, stiff, eroded parts	3	3	9
3	Piston on both sides	F-V.6.1	Galling, seizure, misalignment, pitting	3	2	6
4	Hydraulic line from HPU to BOP Flange and gasket	F-1.13.1 F-1.16.1	Leakage, bursting, plugged line Leakage	2 2	3 3	6 6
5	Shuttle valve (rams and annular	F-1.14.1	Not able to change position	5	1	5
6	Fluid reservoir	F-1.15.1	Rupture of reservoir	1	4	4

4.5 Identification of Performance Standards

Performance standards are set for all identified SCEs (critical components) as a form of standard against which the reliability of the component is measured. It is usually defined by the DH or asset owner or his representative in charge of the process and can be incorporated in the planned maintenance system of the system or equipment. Due to the complexity of a BOP CA408 system, the topmost critical component/SCE in this context will be used to demonstrate the remaining steps of the verification process. Identification of performance standards is presented for the blind shear ram in Table 3 and 4.

Table 3: Safety Critical Element Performance Standard

<table>
<tr><td colspan="6">Safety Critical Element Performance standard</td></tr>
<tr><td>SCE</td><td>Blind Shear Ram</td><td>SCE Number</td><td>V 2</td><td>System Type</td><td>Blow-out Preventer</td></tr>
<tr><td>Role of SCE</td><td>Preventive</td><td>Covering Legislation</td><td colspan="3"></td></tr>
<tr><td>Performance Objective</td><td colspan="5">To cut and seal the drill string, pipe or tubular and protect topside from uncontrolled pressure from the well.</td></tr>
<tr><td colspan="6">Functionality</td></tr>
<tr><td colspan="2">Functional Requirement</td><td colspan="2">Performance criteria</td><td colspan="2">Basis</td></tr>
<tr><td colspan="2">To cut through the drill pipe and seal the wellbore</td><td colspan="2">The blind shear ram shall be capable of shearing the pipe body of the highest grade drill pipe in use, as well as closing off the wellbore</td><td colspan="2">API Standard 53
Shelf state requirement (see Appendix C)
Classification rules (Drill Notation)</td></tr>
<tr><td colspan="6">Reliability and availability</td></tr>
<tr><td colspan="5">Performance criteria</td><td></td></tr>
<tr><td colspan="5">Shall be available at all times for well control activities, i.e. 99.99% availability and reliability</td><td>API Standard 53
API 16A</td></tr>
<tr><td colspan="6">Survivability</td></tr>
<tr><td colspan="5">Performance Criteria</td><td></td></tr>
<tr><td colspan="5">Shall be of sufficient strength as per API 16A</td><td>API 16A</td></tr>
<tr><td colspan="6">Interaction/dependency</td></tr>
<tr><td colspan="2">System</td><td colspan="4">Interaction Dependency</td></tr>
<tr><td colspan="2">BOP Hydraulic Pressure Unit.
BOP Control Unit</td><td colspan="4">Closing of the blind shear ram is dependent on the stored pressure in the HPU.
The appropriate signals are required to be sent for the closing action of the blind shear rams</td></tr>
</table>

4.6 Assurance of critical component integrity

The purpose of assurance of critical component integrity is to demonstrate a required level of availability and reliability. This is carried out through an inspection routine, maintenance, testing routines, failure reports and operation procedures. Means of integrity assurance of the blind shear ram is presented in Table 5.

4.7 Verification in operational phase and documentation

Having identified means of integrity assurance of the blind shear ram, other identified safety critical elements/components are also performed through the same process. A summary of assurance activities is made and incorporated in the maintenance management programme of the unit. Based on component criticality level from the risk matrix, equipment manufacturer requirement and relevant legislation, ICP witnessing schedules both offshore and onshore are defined. The purpose of this verification scheme is to ensure that safety critical components of the BOP as determined in the FMECA hazard identification process remain compliant with performance standard throughout its operational phase. Implementation of the verification scheme provides additional confidence that the Duty Holder’s assurance process of the BOP deemed to be safety critical is suitable for use as intended.

4.8 Change Management for BOP

According to [11], one concern that has arisen is the condition of the BOP system compared to when it was originally commissioned. All major modifications should be subject to a management of change process with regard to their continuous compliance with Performance Standards. It is essential that a review is carried out by the Duty Holder, normally through the relevant Technical Authorities, and a level of Verification by the ICP to ensure that critical components are ‘suitable for use’ following the completion of modifications. The extent of verification may vary according to the complexity of change and this should involve a staged process of review to ensure that modifications are correctly selected, developed and executed.

Table 4: Means of integrity assurance of the blind shear ram

Means of Assurance of Integrity of the Blind Shear Ram					
SCE	Blind Shear Ram	**SCE Number**	2.3	**System Type**	Blow-out Preventer
Role of SCE	Preventive	**Covering Legislation**			
Task Reference	Task Details			Frequency	Performance Standard Reference
Visual Examination	Verify parts have been provided by OEM. Check condition of bland ram cavities. Visually inspect each cavity upper sealing area for any scratches.			12M	F/ S F F
Test	Carry out NDT for blind ram blocks			12M	F/S
Document Review/Audits	Review previous NDT reports. Verify that the BSR installed are capable of shearing drill pipe in the hole under maximum anticipated surface pressures. Review shear test results and procedure used for shearing drill pipe.			12M 12M 12M	F/S F/R&A F/R&A

F stands for functionality, S stands for suitability, R&A stands for reliability and availability, M stands for month.

5. CONCLUSION

Documentation is an important facet of verification which demonstrates the fulfilment of the Duty Holder’s responsibility for implementing a scheme to verify compliance with legislation and that assets are and remain safe to operate. This does not only make the whole process auditable but also gives valuable input to judge the effectiveness of the scheme. The proposed RBV draws its strength from the scrutiny by the ICP. A good coordination and collaboration between the ICP and DH cannot be over-emphasised. Continuous review by both duty holder and ICP will no doubt bring to the fore hazards that have hitherto been either overlooked or have not yet been a source of concern.

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