Risk control in the well drilling phase: BOP system reliability assessment

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ABSTRACT: The blowout preventer (BOP) is the main well control device used to ensure the safety of well drilling and intervention operations. The BOP is qualified for the demanding conditions that may come from uncontrolled flow in the well. However, recent accidents and near misses also show that the BOP fails from time to time. The oil and gas industry has been collecting experience data for BOP systems over many decades, and several reports on BOP safety and reliability performance has been published based on this data. The BOP received increased attention after the Macondo well blowout in 2010, and previous BOP safety and reliability performance estimates have been challenged. The objective of this paper is to evaluate some of the recent safety and reliability studies published on BOP systems. Based on the evaluation a new approach for safety and reliability assessment of BOP stack closure elements is presented with a case study for demonstrating its application. The main benefit of the proposed approach is a more efficient explicit trade-off analysis, where the effect of different maintenance strategies are evaluated against typical BOP safety availability targets.

1 INTRODUCTION

Most oil and gas well reservoirs represent a major source of hazardous energy, and a blowout preventer system (BOP) is used to prevent the escape of this energy during well drilling operations. The BOP is primarily designed so that the drilling crew manually, upon detection, can close-in unintended inflow of reservoir energy that can occur during the operations. If the BOP fails to close and contain the inflow the situation will escalate into what is called a well blowout. An offshore well blowout is not found acceptable across the industry. For example, the Macondo well blowout in 2010 caused 11 fatalities and incurred over 40 Billion USD in liabilities (Reuters 2012). The reliability of BOP systems has therefore received a comprehensive scrutiny in the aftermath of the Macondo blowout. Most importantly, regulations and standards that pertain to design, qualification and use of BOP systems have been subject to revisions (BSEE 2014, API 2004b, API 2012, API 2004a, PSA 2014b, PSA 2014a, NORSOK 2012, NORSOK 2013). In addition, new contingency measures such as well capping devices have been developed for improved emergency preparedness in event of potential failure of a subsea BOP system.

The oil and gas industry has monitored the safety and reliability performance of subsea BOPs for many decades. Data about BOP failures during drilling operations has been collected, analysed and applied as basis for several safety and reliability performance reports published (Rausand & Engen 1983, Holand & Rausand 1987, Holand 1998, Quilici et al. 1998, Holand 1999, Holand & Skalle 2001, Jorge et al. 2001, Jorge 2005, BSEE 2006, Sattler & Gallander 2010, Holand & Awan 2012). Fault tree analysis (FTA) is seen used for the more detailed BOP reliability studies, among other found in the reports by Holand et al. (2012, 2001, 1999), which are considered to be the most thorough.

Recognised industry regulations and standards require verification (testing) of BOP safety functions every 7 or 14 days. It is also a regulatory requirement to pull the BOP for repair if a safety critical failure is revealed during such a test. However, the unscheduled pulling of a BOP for repair may introduce increased well blowout risk, and waivers that allow the drilling crew to postpone repairs are sometimes given by the authorities. Unfortunately, the FTA models developed in the mentioned reports apply to a static situation and do not account for the dynamic effect that waivers have on the well blowout risk level.

The main objective of this paper is to present a new modelling approach that is more suitable in an operational context for decision-making about need for BOP repairs or not. The BOP closure elements are studied using Markov modelling in the approach with degraded BOP states included. The new model may be used to support decisions about different maintenance policies, within the existing industry frames of the typical BOP safety availability targets (NOGA 2004). The paper also gives a thorough definition of BOP operating states, as necessary to understand the assumptions made for the new model.

2 DYNAMIC RELIABILITY ANALYSIS

During well operations the BOP may be regarded as a dynamic system. This includes many different load scenario and possible transitions of the BOP into degraded states of operation, if one or more faults are revealed. Many of the previous safety and reliability studies of BOP systems treat the BOP as a static system using a traditional FTA approach. This section gives a review of how the safety and reliability of dynamic systems is treated in the literature, starting with Hassan & Aldemir (1990) who argue that "dynamic methodologies are defined as those which explicitly account for the time element in system operation for failure modelling". The definition implies focus on time requirements (time-line) over situation requirements (state/'evidence'), which is sought for the safety and reliability analysis of subsea BOP systems. However, the use of the term 'dynamic' about analysis has become broader in more recent years. For example, according to Distefano & Puliafito (2009) it may also be system analysis that explicitly evaluates dependent, cascading, on-demand or common cause failures, and also policies for redundancy and maintenance.

Most dynamic analysis methods for large systems are based on the well-known 'static' analysis methodologies (Rausand & Høyland 2004). Examples of dynamic methods are dynamic fault tree (Čepin & Mavko 2002), dynamic reliability block diagram (Distefano & Puliafito 2009), dynamic event tree (Acosta & Siu 1993) and dynamic Bayesian networks (DBN) (Cai et al. 2013). Many of the dynamic methods retain a strong relation to the time-line for modelling. However, newer methods, in particular those based on Bayesian theory, focus more explicitly on situation requirements, the existing 'evidence' relevant to the system functionality. For example, Cai et al. (2013) demonstrated the application of a DBN in BOP reliability analysis by converting one of Holand's FTA models. Another interesting class of dynamic reliability analysis is referred to as 'multiphase' or 'phase mission system' (PMS) analysis (Siu (1994). This is analysis where the system model consists of a set of sub-models that are consecutively linked together over the (mission) timeline. For example, a typical PMS model may consist of sub-models that are based on reliability block diagrams or fault trees, which for system analysis are linked together with a binary decision diagram (Lu & Wu 2014).

The FTA and DBN models used for BOP safety and reliability analysis are found computational demanding, which makes them less suited for operational use. Also, the FTA and DBN approaches are complex and discipline oriented. Hence, as a representation of a system or process it is viewed (currently) to lack the 'communication features' needed for risk control in a multidisciplinary operational setting (Rasmussen 1997).

Similar to a PMS model the BOP safety and reliability analysis model presented in this paper is based on a recursive multiphase Markov approach that includes a stationary transition rate matrix that can be solved by numerical methods. The multiphase Markov method presented constitutes a detailed model for the BOP system closure elements, but may also be used as a simplified and compact representation of the entire subsea BOP system.

3 SUBSEA BOP SYSTEM DESCRIPTION

3.1 *Description of subsea BOP system elements*

The main BOP safety function is to close-in and control unintended inflow of reservoir energy that can occur during the well operations. The subsea BOP system is made up of three main subsystems to achieve this function (The Deepwater Horizon Study Group 2011): 1) Control system that distributes hydraulic power fluid from hydraulic power unit and accumulator banks used for activation of BOP closure elements. The control systems found are based on two principles; electro-hydraulic ('multiplex') or pilot hydraulic ('all hydraulic'). 2) Lower marine riser package (LMRP) that provides the ability to connect and disconnect the drilling riser (rig) from the BOP stack. For example if bad weather conditions or in a 'drive-off'/'drift-off' situation with a dynamic positioned (DP) rig. 3) The BOP stack that connects and seal the BOP to the wellhead and includes a 'stack' of main BOP closure elements for well close-in, within ca. 30-45 seconds, during different well control situations.

There are three different types of BOP closure elements available for activation in a well control situation; 1) Annular preventer (AP): A 'rubber donut' that is compressed during activation. AP has the ability to seal-off annulus outside all sizes of pipe running through the BOP. Some AP elements can also seal off the well if there is no pipe, but then at a reduced pressure rating. AP is the primary element that is activated during drilling operations. The AP elements are normally located in the LMRP. 2) Pipe ram (PR): two opposing 'ram blocks' with slips and seals that hold the pipe in place and seal-off the annulus outside. A PR element is designed for specific size of drill-pipe. A variable bore ram (VBR) is term used for a PR element designed for a range of drill-pipe sizes. 3) Blind shear ram (BSR); two opposing 'ram blocks' with a cutting edges and seals that will shear specific sizes of drill-pipe and seal off the well. It is common for a subsea BOP stack to have one BSR. Some BOP stacks have a second non-sealing casing shear ram (CSR) designed to cut larger diameter pipe.

The subsea BOP closure elements are all in an open and dormant position during normal well operations not to impede the activities. On basis of how the elements are activated we may define five distinct modes of BOP operation:

1. Intervention – Manual. An underwater remote operated vessel (ROV) can be used to override BOP-functions through ROV tool interface(s) on the BOP stack.
2. Normal – Manual. This is the main BOP operational mode where the drilling crew relates to the situation on the rig floor and the two central BOP control panels.
3. Emergency – Manual disconnect sequence (EDS). The activation of at least one blind shear ram to seal off the well and disconnection of the LMRP from the BOP stack.
4. Emergency – Autoshear. The automatic activation of at least one blind shear ram if the LMRP disconnects spuriously.
5. Emergency - Automatic Mode Function (AMF / 'deadman'). The EDS sequence triggered automatically in situations with loss of power and communication between the rig and the BOP.

3.2 *Regulations and standards*

The most internationally recognised regulations for design, operation and maintenance of subsea BOP systems is provided by the United States Bureau of Safety and Environmental Enforcement (BSEE). The BSEE regulations refer to domestic industry standards; API Spec 16A, API Spec 16D and API Std 53 for guidance on how to fulfil requirements. The following main requirements are found related to subsea BOP system design in the BSEE's federal regulations (BSEE 2014)

- Two redundant BOP control panels whereof one panel on the drilling floor.
- At least four remote controlled BOP rams/ preventers, thereof: One AP, two PR/VBR (for each size of drill-pipe used) and one BSR. BSR to shear any type drill-pipe/work-string/tubing.
- Independent dual pod-control system for operation
- Accumulators that provide 'fast closure' (emergency mode) of the BOP components in case of loss of power fluid connection to the surface
- ROV intervention capability (intervention mode) for override of minimum one PR/VBR, one BSR and the LMRP connector (disconnect).
- Autoshear and deadman systems for DP rigs (emergency mode)
- Side outlets on the BOP stack for a separate kill and choke lines. Each outlet with at least two remote controlled and full-opening valves. Install a choke line outlet above the bottom ram and a kill line outlet below the bottom ram.

In Norway, the Petroleum Safety Authority Norway (PSA) refers to NORSOK standard D-001 (NORSOK 2012) to meet requirements stipulated for equipment used in well drilling operations. There are some differences in requirements between BSEE and PSA. In comparison to the BSEE regulations as the main reference for such systems the following is noted in the Norwegian regulations:

- BOP control system that meet recommendations in OLF 070 (NOGA 2004), which stipulates SIL 2 requirements (IEC 2010) for closure of PR/VBR or BSR in two defined well control situations.
- LMRP disconnection system that secures well and disengages the riser before a critical riser angle occurs.
- Two shear rams where at least one is capable of sealing.
- For DP vessels; Shear ram that can shear casing and drill-pipe tool joints / heavy walled pipe.
- For mobile offshore drilling units the BOP shall be equipped with two annular preventers.

An illustration of two main BOP closure element configurations from the regulations and experience data is shown in Figure 1.

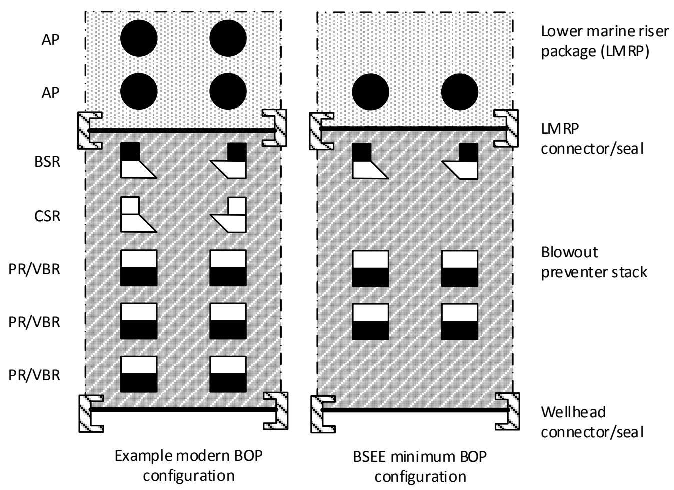

Figure 1. Example of BOP closure element configurations

3.3 *Operation and maintenance*

After the BOP installation testing the BSEE provides requirements to BOP function- and pressure testing every 7 and 14 days during the well operations. The BOP closure elements require pressure testing (14 days) for verification of both closure and seal for relevant well load scenario, but reliability data collected shows that most control system failures are revealed by function tests (Sattler and Gallander, 2010).

3.4 *Summary*

Seven distinct BOP well isolation (close-in) scenario has been identified from a technical review, which also are illustrated in Figure 2. Note that 1ooN denotes a system that functions as long as at least one out of total of N elements are functioning;

- 1a) Low well pressure scenario with drill-pipe in hole: Isolation of annulus with AP or PR/VBR elements available (1oo3, 1oo4, 1oo5)
- 1b) Low well pressure scenario with casing in hole: Isolation of annulus with AP elements available (1oo1, 1oo2)
- 2) Drill-pipe in hole: Isolation of annulus with PR/VBR elements available (1oo2, 1oo3)
- 3a) Low well pressure scenario with no pipe in hole: Isolation of well with AP or BSR elements available (1oo1, 1oo2, 1oo3)
- 3b) No pipe in hole: Isolation of well with BSR element available (1oo1)
- 4a) Drill-pipe in hole: Automatic isolation of well with BSR element available (1oo1)
- 4b) Casing in hole: Automatic isolation of well (Not evaluated)

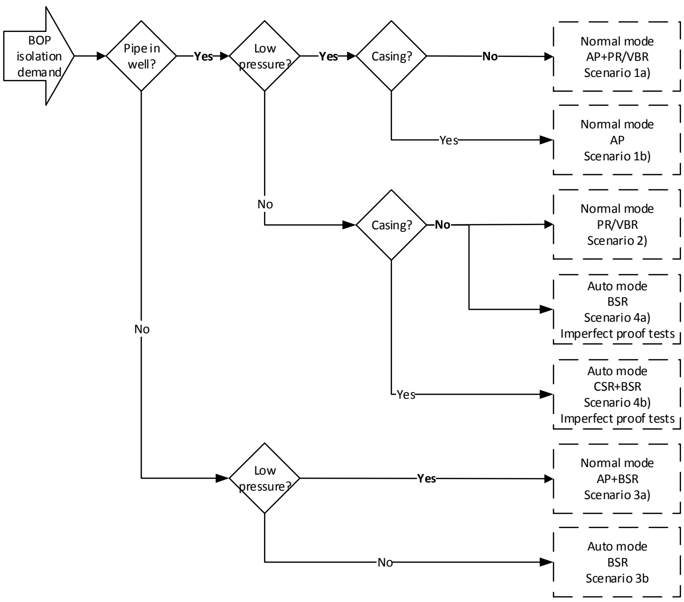

Figure 2. BOP closure demand scenario

4 RELIABILITY ASSESSMENT

4.1 *Modelling basis and experience data*

A safety and reliability model must reflect the system in those aspects that are of importance to produce trustworthy results. For guidance on model validity independent on well isolation scenario, Table 1 presents a list of the historically most severe, safety critical BOP system failures from Holand & Awan (2012), Holand (1999) and BSEE (2013). The data indicate the control system as a potential source for common cause failures (CCF). Also of main interest is TAR project no. 455 (BSEE 2004) stating that the BSR may fail in 50% of the times when attempting to shear pipe during actual operations. On same subject Holand and Awan reports (2012): "In the Phase I deep-water study, a failed to shear pipe occurred during an emergency disconnect. For the two emergency disconnect situations observed in this study, the BSR successfully cut the pipe and sealed off the well".

Table 1. Overview of critical subsea BOP system failure modes with relevant reliability data based on (Holand 1999, Holand & Awan 2012)

Item and failure mode	MTTF* (BOP days)	MTTF* (Item days)
Wellhead connector - External leakage (2of)	11128	11128
LMRP connector - Spurious disconnect (2of)	11128	11128
LMRP connector - Failure to disconnect on command (3of)	7419	7419
Control system - Total loss of BOP control (by the main control system) (7of)	3179**	3179
Control module (POD), single - Total loss of POD functions (20of)	1113	2226
Control PODs (2of) - Simultaneous loss of one function in both PODs (6of)	3709**	3709
BSR - Leakage in closed position (4of)	5564	6276
BSR - Failure to close on command (1of)	22256	25104
BSR - Failure to shear pipe in LMRP disconnect situation (1of)	NA	NA
BSR - Spurious closure (1of)	22256	25104
PR/VBR - Leakage in closed position (7of)	3179	8613
PR/VBR - Failure to close on command (2of)	11128	30147
PR/VBR - Failure to open on command (2of)	11128	30147
AP - Leakage in closed position (11of)	2023	3704
AP - Failure to close on command (1of)	22256	40748
Isolation valve on choke and kill line out-let - External leak (1of)	22256	NA
Choke and kill line - External leaks (Note; presumably downstream the isolation valves on BOP stack outlet) (13of)	1712	NA

Flexible joint (item is located above LMRP, and not part of well barrier envelope) - External leakage (2of)	11128	11128

*) Based on average BOP ram/preventer configurations in datasets. Total of 22256 BOP (installation) days and 482 wells drilled.

**) Produces an estimated CCF average rate of less than 1/22256 = 4.5E-5 /BOP day for rams and preventers (λ_{CCF}). Note respectively ~13/22256 = 5.8E-4 /BOP day for control system failures.

4.2 *Basis for new approach*

A BOP closure demand from unintended inflow of reservoir energy into the well may occur at random due to insufficient mud density, mud losses, riser failure, spurious disconnect of LMRP, or DP rig drive-off or drift-off. Aside relevant action from the drilling crew, the probability of a loss of well control ('blowout') in such situations will be equal to the probability of failure on demand (PFD) of the BOP. If we assume that the demands follow a homogeneous Poisson process (HPP), with a known rate γ, it is straight forward to model the associated well blowout frequency. By combining the HPP with the binomial situation, the number $N_{BO}(t)$ of blowouts caused by the demand in the time interval [0, t) will be a new HPP with frequency $\gamma \cdot PFD$ (Rausand & Høyland 2004). The probability that a drilling operation will 'survive' an operations length of, say 60 days, without a blowout is thus given by:

$$\Pr(\text{"survive 60 days"}) = e^{-\gamma \cdot PFD \cdot 60}$$

Most of the safety critical BOP failure modes are hidden, and regular function- or pressure testing is carried out to reveal such failures. The safety and reliability performance of a proof tested system is often measured by the average PFD, PFD_{AVG}. The PFD_{AVG} is mainly influenced by two parameters: (i) the rate of hidden failures of BOP elements (λ_{DU}), and (ii) the interval between two consecutive tests (τ). For a system of several BOP closure elements, the PFD_{AVG} becomes (Rausand 2014):

$$PFD_{AVG} = 1 - \frac{1}{\tau}\int_0^\tau R_S(t)\,dt$$

where $R_S(t)$ denotes the reliability ('structure') function of the BOP closure element configuration.

Assuming regular test intervals and perfect repairs, we may assume that the PFD_{AVG} takes the same value in all intervals, and PFD_{AVG} is thus the probability of the BOP failing to close *at any time*. Rausand (2014) presents simplified formulas for 1ooN systems of N identical elements subject to independent failures and CCFs (λ_{CCF}). For 1ooN BOP element configurations shown in Figure 3 we get:

$$PFD_{AVG} \approx \frac{(\lambda_{DU} \cdot \tau)^N}{(N+1)} + \frac{\lambda_{CCF} \cdot \tau}{2}$$

For instance, if we assume 1oo2, λ_{DU} = 1/627 (days), τ = 14 days, and λ_{CCF} = 1/22256 (days) we get PFD_{AVG} = 4.8E-4. Alternatively, with λ_{DU} = 1/1173 we get PFD_{AVG} = 3.6E-4. For 1oo3 with same input we get PFD_{AVG} = 3.2E-4. The failure rate assumed, λ_{DU}, is based on the overall MTTF data provided for AP element in Holand and Awan (2012), and appear conservative to the safety critical MTTF presented in Table 1. However, the AP input data is selected for purpose of the case studies, based on the conservative view that closure element failure always cause impairment of the element safety functions if a needed repair is postponed.

The PFD_{AVG} formula presented is based on a number of assumptions, which of main are:

1. The failure rate of the BOP elements are identical and independent of time. Several BOP elements are, however, non-identical (an AP is not the same as a PR/VBR or BSR)
2. All failures are detected during the proof test and within a negligible period of time. This assumption is clearly not valid for the BSR. The cutting of pipe and sealing is not (for obvious reasons) part of regular tests. However, every 3 to 5 year the BSR is 'overhauled', and it may be assumed that most deficiencies that could result in cut and sealing failure are revealed then. If Taylor series approximation still holds, $\lambda \cdot \tau < 0.01$, we may use time between overhauls as the 'test interval' of the shear function. However, care should be taken since the experience data indicates a high PFD of the BSR in an actual shear-demand situation.
3. All items are repaired to "as good as new" condition within a negligible period of time after failure detection. This is not always the case, or desirable, since it is possible in some cases to postpone repair of the BOP ('waivers given').

4.3 *New approach based on multiphase Markov*

Reference is made to the BOP closure demand scenario presented in Figure 2. A Markov model will allow the modelling of a degraded BOP system, but the number of elements to consider must also be restricted to avoid an undesired state explosion. The main idea behind the new approach is to incorporate the effects on well safety of postponing repairs, taking into account that BOP configurations have many redundant BOP closure elements. A similar multiphase

Markov model, but with another application area, has been developed and discussed by Welte (2008).

The Markov model in the approach is illustrated in Figure 3. In the model we assume N number of identical redundant BOP closure elements. ML denotes the maintenance level, which represents the degree of allowable degradation, the number of revealed failures, before the BOP is pulled for repair. I.e., the BOP will be pulled to surface for overhaul and full renewal (perfect repair) if the total number of revealed failures reaches or exceeds the ML value. Noted is bounds for the model with ML = 1 that equals a 1ooN system, and ML = N that equals a system that is not repaired until all redundant elements have revealed failures.

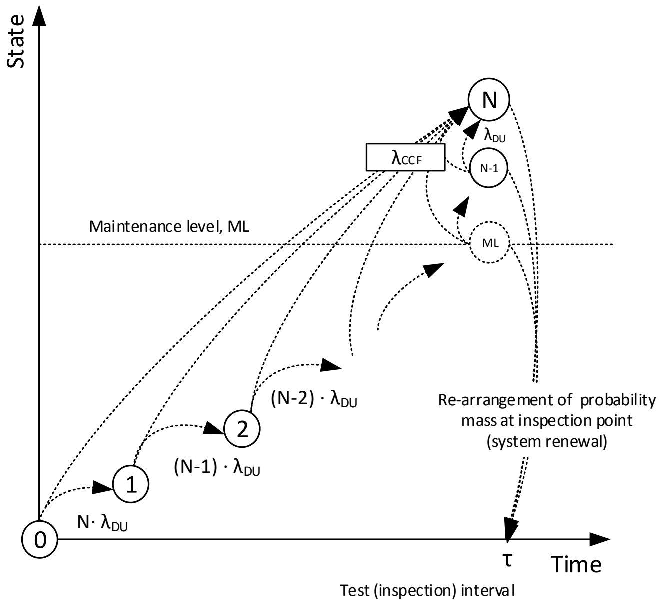

Figure 3. Illustration of multiphase Markov model

The model is made recursive, so that a numerical routine can be implemented to automatically solve over many inspection intervals within the total BOP installation period on the well.

According to Chapman-Kolmogorov's equation the Markov model in Figure 3 is given with N+1 states as (Rausand 2014):

$$\mathbf{P(t)} \cdot \mathbf{A} = \mathbf{P'(t)}$$

$$[P_0(t)\cdots P_N(t)]\cdot\begin{pmatrix} \lambda_{00} & \cdots & \lambda_{0N} \\ \vdots & \ddots & \vdots \\ \lambda_{N0} & \cdots & \lambda_{NN} \end{pmatrix} = [\frac{dP_0(t)}{dt}\cdots\frac{dP_N(t)}{dt}]$$

Where the **P(t)** vector includes the distribution of the probability mass between the states at any time t, and hence; $P_0(t)+P_1(t)+ \ldots +P_N(t) = 1$ is required for $t \geq 0$. In the transition rate matrix **A**, we have $\lambda_{i,k}$, for i ≠ k, denoting the incoming transition rate from state i to state k. If no possible transition from state i to state k then $\lambda_{i,k}$ = 0. Respectively, $\lambda_{k,j}$, j ≠ k, denote outgoing transition rate from state k to state j. If no possible transition exist from state j to state k then $\lambda_{k,j}$ = 0. As illustrated in Figure 3 the approach uses a stationary **A** with transition rates $\lambda_{N-1,N} = \lambda_{DU} + \lambda_{CCF}$, and otherwise not equal to 0 for i = [0, 1, …, (N-1)] given by:

$$\lambda_{i,N} = \lambda_{CCF}$$
$$\lambda_{i,i+1} = (\mathrm{N}-i)\lambda_{DU}$$
$$\lambda_{i,i} = -(\lambda_{CCF} + (\mathrm{N}-i)\lambda_{DU})$$

The start conditions will resemble a continuous time Markov chain model with all probability mass located in state 0, $P_0(0) = 1$. State 0 will represent the "as good as new" condition of all N redundant BOP closure elements. From the Markov property, **P(t)A=P'(t)**, that is valid between inspection times we may use the following to numerically solve the movement in the state's probability mass (Rausand 2014):

$$P_k(t+\Delta t) = \sum_{\substack{i=0 \\ i\neq k}}^{N}\left[P_i(t)\cdot\lambda_{i,\mathrm{k}}\cdot\Delta t\right] + P_k(t)\cdot(1+\lambda_{\mathrm{k,k}}\cdot\Delta t)$$

Further, iteratively at each inspection point τ_i we move all the probability mass from states; $P_{ML}(\tau)$, $P_{(ML+1)}(\tau)$, … $P_{(N)}(\tau)$ and add this back to state 0. This produces the new start conditions **P(0')** for this period (phase) till the next inspection time and so forth until the mission time is reached. A typical mission time will be 60-70 days for a BOP. I.e., the BOP is then pulled to surface for maintenance and preparations for use on the next well.

Based on the approach, we may directly produce for decision support (i) the PFD and thereof PFD_{AVG} : The PFD of 1ooN configuration is equal to $P_N(t)$, (ii) the probability of having to pull the BOP at inspection point τ_i, which is equal to the $\sum_{m=ML}^{N} P_m(\tau_i)$. The PFD result from model can for instance be combined with a control system PFD analysis for verification of SIL 2 requirement (PFD_{AVG} < 1E-2) as stipulated in NOGA (2004).

5 CASE STUDIES

Figure 4 and Figure 5 show results from selected 1ooN configurations under key assumptions of proof test intervals; 14 days stipulated by BSEE and 21 days by API Std 53, and of conservative AP BOP element failure rate input (see section 4.2). In particular it is noted from the figures that a ML of less than N-1 produces a fairly constant ('robust') PFD value within the 70 - 84 day selected mission time. This indicates that a decision to postpone repair until the (N-1)th revealed closure element failure may be an option due to small impact on the 'BOP system PFD'. However, a careful check of assumptions and analysis with input data relevant to the actual BOP should be performed before making any decisions. Noted is also that verification of NOGA (2004) SIL 2 requirements appear to be within reach of most BOP system configurations, which is also demonstrated in FTA model calculation made by Holand and Awan (2012).

Steady-state PFD from the model was not produced during the case studies with a selected mission time of around 70-80 days in spite of relative high input failure rates. Care must therefore be taken when deducing PFD_{AVG} from the model. For example, a high impact on the numerical PFD_{AVG} value is found from a strong transient PFD in the first 14 or 21-day inspection interval. A rule of thumb in the oil and gas industry is to approach safety policy changes from a conservative side. Hence, we would suggest that PFD in 1st interval is neglected when producing PFD_{AVG} with the model. For the case studies, neglecting the first inspection interval for PFD_{AVG} calculations implied some 11% to 25% increase in the average value. The PFD_{AVG} increase was highest in cases with small N.

6 CONCLUSIONS AND FURTHER WORK

The boundary conditions for safety and reliability analysis of subsea BOP systems have been thoroughly discussed on basis of internationally recognised regulations, industry standards and experience data collected by the industry.

A multiphase Markov modelling approach has been presented that can be used to explicitly evaluate aspects of safety performance and maintenance optimisation for typical subsea blowout preventer systems. Several case studies have been presented to demonstrate the application of the approach for typical BOP system configurations under normal operating conditions, which are referred to in the paper as "Scenario 1a/b" and "Scenario 2": Isolation of well annulus with AP or PR/VBR elements available.

A main assumption with the approach, a trade-off for model simplicity, is that all the BOP closure elements must have identical failure rates. Experience data shows that this can be a valid assumption, but same experience data may also be used to argue the need to use different failure rates. Hence, it may be of particular interest to study the implications of this simplification in the model. For example, what are benefits to a more detailed model over the simplistic alternative and use of sensitivity analysis?

7 ACKNOWLEDGEMENTS

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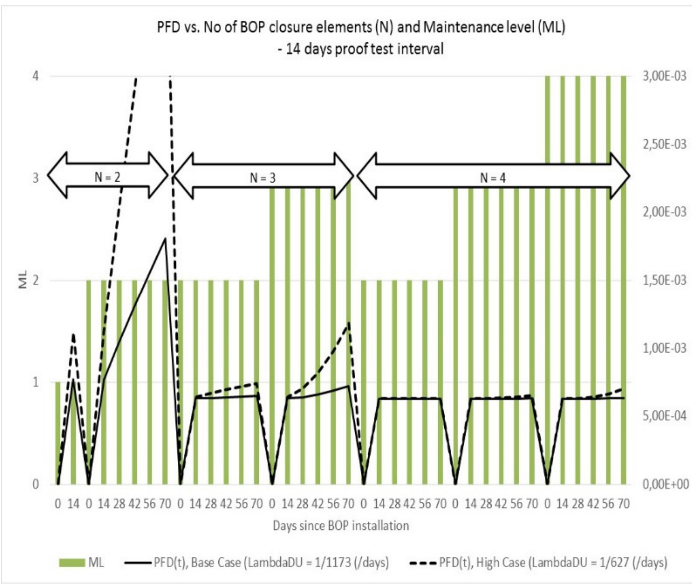

Figure 4. Case study 1 results of new approach

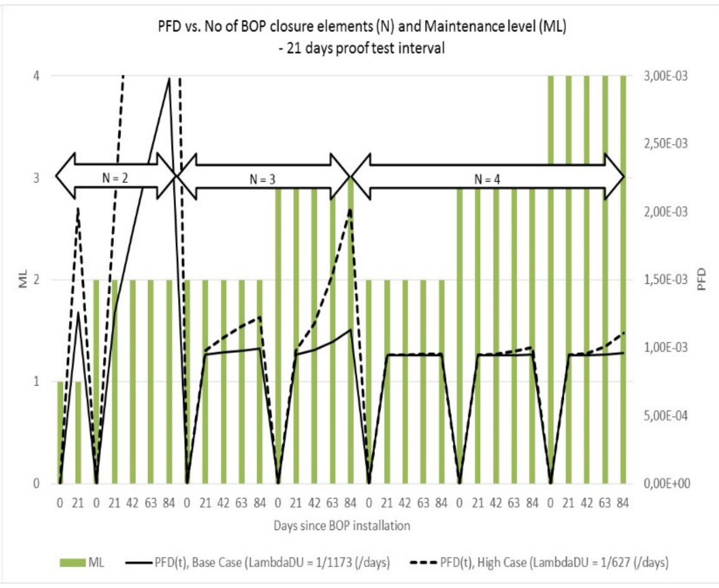

Figure 5. Case study 2 results of new approach

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