Offshore Drilling Blowout Risk Model – An Integration of Basic Causes, Safety Barriers, Risk Influencing Factors and Operational Performance Indicators

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Offshore Drilling Blowout Risk Model – A Comprehensive Integration of Basic Causes, Safety Barriers, Risk Influencing Factors and Operational Performance Indicators

Offshore drilling is an activity inherent to the oil and gas industry as it is essential for confirming the economic feasibility of hydrocarbon reservoirs. However, operational uncertainties and risks inherent to typical major accident hazards are associated with the performance of this activity, where blowouts are assumed to be one of the major contributors to risk in offshore drilling.

This paper presents an accident precursor risk model for offshore drilling blowouts that integrates the blowout basic causes, safety critical barriers & elements, Risk Influencing Factors (RIF) including Human and Organizational Factors (HOF), and Operational Performance Indicators (OPI). The method, which was adopted to design the model and allow its customization for reflecting the characteristics of any drilling rig, well and operation is also described and demonstrated using a theoretical example. The model is hybrid, as it combines bow-tie diagram (fault tree and event tree) with directed acyclic graphs (DAG), to account for the effect of the RIF on the performance of safety barriers through the direct observation of pre-defined OPI.

Keywords: Quantitative risk analysis (QRA), Blowout, Risk Influencing Factor (RIF) and Operational Performance Indicators (OPI).

1 INTRODUCTION

The risks inherent to drilling projects must be assessed prior to and during operations. Risk assessment studies are part of the regulatory framework of many countries and are critical documents for the permit process of drilling activities. For instance, the UK (Health and Safety Executive, 2006), states that the primary objectives of risk assessment in this context are to identify and rank risks so that they can be adequately managed, and to examine associated risk reduction measures to determine those most suitable for implementation.

However, blowout risk models frequently do not properly address the characteristics of the project that can affect blowout risk. A review of several blowout risk assessment studies performed by the authors reinforced what was already shown by (Skogdalen & Vinnem, 2012), which is that most of these studies are similar and generic. Most risk models do not address the characteristics inherent to the basic causes of the kick, which is the major blowout accident precursor. In addition, quantification is limited to reviews of accident frequency databases that, in most cases, are not adjusted to the characteristics of the system and operations. As a consequence, specific risk influencing factors (RIF) of geology, equipment, systems and human and organizational factors (HOF) are not considered in the risk model, as those have already been discussed and demonstrated by other authors (Vinnem, 2007); (Skogdalen & Vinnem, 2012); (Skogdalen & Vinnem, 2011).

The aim of this research paper is to propose an accident precursor blowout risk model, designed so that it can be easily expended and customized to reflect the characteristics of the well, drilling rig and operations. It must also account for and integrate basic causes, safety critical barrier elements & systems, RIF, and Operational Performance Indicators (OPI).

This research paper is divided into three major parts:

- **Section 2 -** This section is focus on safety and reliability professionals who are not familiar to drilling and so, presents a general background on drilling engineering and the causes of blowouts, including a description of the safety critical barriers and Operational Performance Indicators (OPI) for detecting a kick, the blowout accident precursor.
- **Section 3** – Describes the methodology adopted to design the proposed model and provides further guidelines to customize it for a specific project.
- **Section 4 -** Presents the results of the application of the methodology by: i) suggesting a comprehensive blowout risk model (Section 4.1), and; ii) providing an example of further customization for reflecting the specific conditions of a drilling project (Section 4.2).

2 BACKGROUND IN DRILLING ENGINEERING AND BLOWOUT

2.1 Basic concepts on drilling engineering

The drilling of a wildcat or exploratory well is still the only way of confirming the existence of a hydrocarbon reservoir, and a success rate of only one in four wells gives some indication of the difficulties encountered in determining the existence of hydrocarbon deposits (Thomas, 2001). When hydrocarbons are encountered, a well test is conducted to evaluate the reservoir's potential to produce hydrocarbons.

A drilling project is characterized by different stages in preparation for well construction. The first stage is the design phase, which depends on the results of an overall assessment of the area to be drilled. This phase of the project requires geological studies and a review of historical data gathered from wells previously drilled in the area.

The data gathering process is critical to the success and safety of the drilling operations from the beginning of the project. Geological and geophysical (G&G) uncertainties can be reduced when more information is available, minimizing the project's risks. This stage may also include geotechnical investigations to identify possible geological hazards (geohazards). Geohazards include risks related to irregularities in subsea topography, that are critical to determining the exact well head location – with the subsurface target in mind – which consequently impacts the following stages of the project. Another example of a geohazard is the presence of shallow gas in the area (Thomas, 2001). These types of hazards are not covered in this research paper, which focuses on deep blowouts.

During the design phase, certain risk-averse assumptions are usually made, resulting in well designs catering for worst-case conditions. This approach is preferred by oil companies due to the uncertainties involved in all the steps of the design as well as the fact that most wells have historically been designed in a deterministic manner (Dahlin, Snaas, & Norton, 1998). Uncertainty is higher in deep-water wells, especially if they are exploratory. All uncertainties regarding pore pressure (p_p), fracture (p_f) and temperature gradients add up (ΔT), and the design factors on casing design need to be higher to account for these uncertainties.

Once the Geology and Geophysical (G&G) department estimates the lithology and selects the 'target', defined as the precise place in the reservoir that must be intercepted by the well, a critical phase of the well design begins: the estimation of geo-pressures. The geo-pressure study consists of calculating the existing underground stresses and which of them affect the formations. This study calculates the following data as a function of depth (D), using empirical models: over burden pressure (p_{ob}), pore pressure (p_p), collapse pressure (p_c), and fracture pressure (p_f) (See **Figure 1**). As well as being essential for proceeding with the design of the well, geo-pressure estimation indicates the gradient window (or operational window) for drilling operations. The gradient window defines the lower $(W_{m_{min}})$ and upper limit $(W_{m_{max}})$ of the drilling fluid density (called mud weight (W_m)), equivalent to the hydrostatic pressure (p_h) applied to the borehole to maintain its integrity (primary well control) (Rocha & Azevedo, 2009; Thomas, 2001). For exploratory wells categorized as wildcats, in areas where offset wells are not available, seismic images may be used to assess structural and stratigraphic traps, and to estimate gradients, enabling a preliminary geohazard analysis and constituting an important risk mitigation measure.

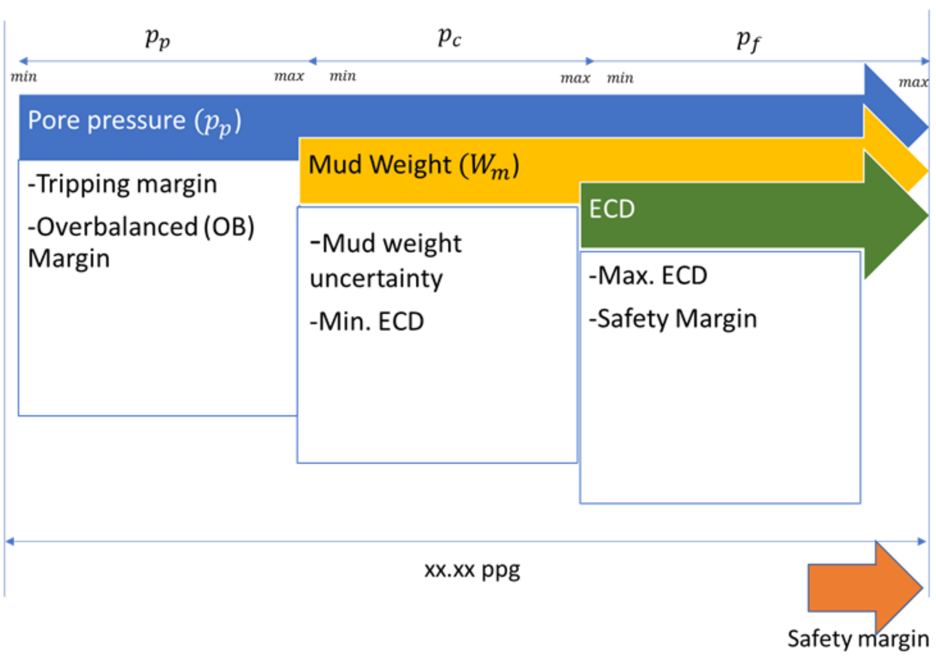


Figure 1: Example of operational window modified from (International Association of Drilling Contractors, 2015).

These sets of information are the main components of the geological prognosis and the basis of the design - the starting point for a detailed drilling program. The detailed drilling program consists in combining well trajectory with pressure gradients, mud weights and the casing program. The well trajectory is determined based on subsea geological characteristics, the formation lithology and in-situ stresses, the depth, azimuth and horizontal displacement of the potential production zone, the type of technology to be used in the Bottom Hole Assembly (BHA) and the type of drilling unit that is likely to be utilized.

As a result of this stage, the operational performance indicators (OPI) related to G&G risk factors may be identified. These are the main operational parameters that are monitored and controlled during well construction. An indicator is a variable (x) that can measure a change in the condition of a broader phenomenon or situation. For the purposes of this paper, an operational performance indicator (OPI) is defined as an indicator used during operational time, capable of quantifying the condition or the status of the entire drilling operation, measuring the effect or influence of these changes in the risk of a major event. An "event" (E) in this paper is identified as any deviation from the normal operation status or safety condition (Resvold Tranverg, 2013; Tamim, Laboureur, Mentzer, Hasan, & Mannan, 2017). The safety condition h is a function of the variable (operational parameters) and the constraints (a,b) that the operation needs to satisfy. These constraints are mainly identified as minimum and maximum values for operational parameters (Tamim et al., 2017).

$$h(x) = \{x: a \leq x \leq b\} \qquad \textbf{(Equation 1)}$$

The use of safety performance indicators to evaluate the operational trend and monitor the level of risk comes from the nuclear industry. There are two kinds of performance indicators: leading indicators and lagging indicators. Leading indicators are preventive and proactive, they may be used as safety precursors to identify the barriers degradation for management and operators to response. Lagging indicators are measurements used to compare performance between similar facilities or to measure the complete performance of the plant as a benchmarking assessment (Hopkins, 2011). Both kinds of indicators are very useful; however, the former are more operational and could help to identify the safety level of the process and prevent major accidents.

The operational performance indicators (OPI) are dynamic and considered to be leading indicators, implying they are preventive, and may be modified as the process goes forward. For example, the percentage of personnel with High Pressure High Temperature (HPHT) training, the percentage of people with *z* levels of experience, and the percentage of people with *y* level of awareness.

However, lagging indicators are indicators that are useful to provide the picture of the installation at a specific moment (operational time), but are not expected to change during the overall operation (Øien, Utne, & Herrera, 2011; Reiman & Pietikäinen, 2012). Examples would include: near misses, process incidents (kick for instance), breakdown of safety critical equipment and leakages.

The relationship between operational performance indicators (OPI) and risk influencing factors is established by the relationship between the awareness indicators (e.g. kick detection, based on the identification of kick tolerance and effective killing procedures). For example, the RIF related to training and competence could be identified by 3 main indicators: personnel experience, training and awareness. The three lagging indicators of the RIF could have an impact on the detection of low pressures, correct mud preparation, detection of integrity barrier failure, and management of changes in design. The well design process might change slightly, as all these variables are assumed to be interdependent, making the workflow an iterative process as opposite to a single linear process.

The next stage of a drilling project is the well construction, the beginning of which is known in the industry as “spud-in". This stage consists of four main activities: drilling, tripping, casing and cementing. Drilling and tripping operations can be described as geological layers being drilled through by a rotating drill bit, connected to a drill string (a string made up of Drill Pipe joints, working in tension and transmitting torque to the bit), which applies part of its weight to the formation. The drilling fluid (or mud) is pumped at pressure through the string with the purpose of overcoming pressure losses, achieving minimum annular velocity that ensures hole cleaning (cutting transportation to surface) and balancing formation pressure in specific operational conditions:

- Static conditions: pumps off;
- Swab effect: small clearance between BHA and borehole walls jointly with fluid viscosity lead to a negative pressure when pulling the string, reducing the amount of overbalance and potentially causing a kick;
- Surge effects: opposite of swab, leading to excessive overbalance hence fluid losses or fracturing;
- Impact of cutting loading (suspended cuttings of high specific gravity) on Equivalent Mud Weight increase (EMW);
- Trip margin: amount of additional MW required as a safety margin prior to POOH string (in case of a kick, well control is much more difficult without string in the hole, due to the impossibility to circulate);
- Equivalent Circulating Density (ECD): The effective density exerted by a circulating fluid against the formation that takes into account the pressure drop in the annulus above the point being considered.

The mud is critical for maintaining well integrity through hydrostatic pressure (p_h). The casing and cementing phase starts with the installation of a large diameter steel pipe known as a conductor. Typically, a 30 to 36-inch diameter pipe (conductor) is installed, with the aim of preventing hole collapse and providing a conduit for circulation (fluid return) for the subsequent hole section, avoiding severe wash outs (mud circulation causing unwanted hole enlargement due to excessive flow rate and/or unconsolidated formation) or losses. Oil and gas wells are drilled in different sections, with decreasing diameters as depth increases. As detailed by Thomas (2001), the number of phases depends on the geological characteristics of the formation and the total depth of the well. After having been drilled, each phase is completed with the installation and cementation of a casing string. Casing strings have different functions according to the section they cover, including: preventing borehole collapse, avoiding contamination of underground fresh water layers close to the surface, avoiding migration of fluids from the formation, and sustaining the well head and well control equipment.

The management of well integrity during well operations involves the placement, maintenance and testing of adequate barriers throughout the process, preventing the escalation of a well control event (International Association of Drilling Contractors, 2015). **Table 1** presents the relationship between the operational barriers and the previously mentioned four drilling phases of well construction.

Table 1: Physical barriers and their relevance during drilling phases.

Physical barrier	Drilling Phase		
	Drilling	***Tripping***	***Casing and Cementing***
Drilling fluid	x	x	
Casing			x
Cement			x
Casing shoe			x
Wellhead seals/CHSA			x
BOP	x	x	
Cement Plug			x

2.2 Immediate causes of blowout and well control barriers

A blowout is an uncontrolled influx of hydrocarbon released into the environment (atmosphere or underwater) as the ultimate consequence of a kick. A kick is an unexpected flow of formation fluids into the wellbore that occurs when the following conditions are met simultaneously:

- The hydrostatic pressure inside the wellbore is lower than the pore pressure of the permeable formation (underbalance), including not only reservoirs but any other fluid bearing formations ($p_h < p_p$);
- The formation is sufficiently permeable; and
- The fluid viscosity is low enough to allow it to flow ($\rho_f < \rho_{f_{min}}$).

By meeting the presented geological and geophysical (G&G) conditions, a blowout may result from one of the following basic causes (Robert. & Grace, 2003; Rosenberg & Nielsen, 1997):

- Mud weight becomes lower than formation pore pressure $(W_m < p_p)$ due to a failure in filling the hole (in this case we refer to equivalent mud weight) or due to mud density not being properly selected or prepared and maintained on-site. These issues become complex to foresee and assess in deep water drilling, where high temperature and pressure conditions have substantial effects on mud density (ρ_f) and rheology (the science and study of the deformation and flow of matter);
- Failure to keep the hole full while tripping, i.e, when pulling the drill string out of the hole;
- Swabbing while tripping;
- Insufficient Wait On Cement (WOC) and uncontrolled flow at surface during wellhead/BOP work;
- Abnormal formation pressure;
- Insufficient mud level in the annulus / lost circulation.

Ensuring the availability and effectiveness of well control barriers is critical when drilling into the reservoir. A well barrier is defined by NORSOK (2004) as an envelope of one or several dependent barrier elements preventing fluids or gases from flowing unintentionally from the formation into another formation or to the surface. Well barriers are divided into primary well barriers and secondary well barriers.

The primary barrier is the hydrostatic column of the fluid that controls formation pressure during well construction or workover activities, i.e. maintains the well integrity in the drilling phase, whereas the secondary barrier is composed of the systems that are responsible for responding to the kick when it occurs, more specifically the blowout preventer system (kick detection system is not considered as a barrier from the well control standpoint, although it constitutes a system of barriers from the risk analysis standpoint).

Consequently, the following systems are considered as safety critical for preventing the risk of blowouts: the mud system; the kick detection system and its indicators, and the blowout preventer system.

2.3 Blowout safety critical systems

2.3.1 Mud system

The safety function of the mud system is to maintain the integrity of the primary well control barrier, which is the hydrostatic column of fluid that controls formation pressure during well construction or workover activities. This system has two major failure modes: failure in delivering the adequate mud weight and failure in delivering sufficient mud volume to fill up the well when mud loss occurs.

Insufficient mud weight may result from several factors, most of them directly or indirectly related to human and organizational factors (HOF), for instance:

- A misjudgement of well conditions as a consequence of human error or instrumentation failure (penetration rate, cutting shape and size, gas readings, D Exponent or Sigma Log);
- Accidental dilution of the mud by drill water in the active tanks;
- Mud being cut by gas, water or oil, which impacts the mud density;
- An erroneous pore pressure estimate, as in the instance of an exploratory well hitting the crest of a reservoir with a gas cap;

- An unexpected non-sealing tectonic fault being penetrated and causing pressure communication with deeper and/or overpressure zones.

Abnormal formation pressure may also cause the failure of the primary well control barrier. Note that in the case of a low permeability formation, the fluid might flow at such a low rate that the section might be cased off before the influx becomes a threat. Other signs of an underbalance condition are sloughing or heaving shales, and excessive hole fill (Blakeston, 2011).

Circulation losses may be caused by excessive ECD (related to flow rate and mud properties) or surge pressures such as sudden string movements or abrupt activation of mud pumps without staging up gradually when the bit is near the bottom of the hole. In case of severe losses into non-sealing faults, natural or artificial fractures, or depleted layers, the mud level in the annulus will decrease. If the hydrostatic column drops below the level corresponding to equilibrium with formation pressure, a particularly dangerous kick may occur, as the influx will not be detected until it replaces the lost volume. Such volume might be well over the design kick tolerance margin.

2.3.2 Kick Detection System and Kick Indicators

The function of the kick detection system is to ensure that the kick is detected before hydrocarbons reach the blowout preventer (BOP). The warning signs of a kick during drilling are nearly equivalent to those in offshore shallow water or land operations, and are divided into two categories: positive indicators of kick during drilling and signs that the condition of near-balance or underbalance is approaching. Positive indicators of a kick during drilling are:

- A flow rate increase at returns. In a closed system at regime, an increase in returns at the flow line is equivalent to a net gain. In a floating vessel, heave and roll may mask small increases in flowrate, Managed Pressure Drilling systems circumvent this problem by allowing detection of small influxes independent of rig type and sea conditions. To summarize, an increase in returns is a definite sign of a kick in progress;

- Pit volume increase. This is similar to a flow rate increase: in a closed system, a pit gain is a definite sign of a kick, however this sign will appear a few minutes after the flow shoe has seen the kick. At this point the kick volume will be much larger and more dangerous, from here there is a need for early kick detection;
- Pump pressure decrease/pump stroke increase. The formation influx reduces the hydrostatic pressure in the annulus, and as the drill pipe hydrostatic is not affected, U-tubing will occur and the pump will not need to provide as much energy.

Signs that the balance or underbalance condition is approaching warns the operator that there is a risk of meeting the geological and geophysical (G&G) conditions necessary for a kick: porosity, permeability and underbalance condition (which may be due to an overpressure regime). The following operational drilling parameters may indicate the presence of one or more geological and geophysical (G&G) risk influencing factors:

- Depth. The depth is not an indicator by itself, however the top reservoir / target is estimated based on relevant studies and several other factors. The entire well design has its foundations on the geological prognosis (target depth and position, gradients, formation tops), and an accurate estimate greatly reduces operational risks.
- Oil and/or gas shows. These are spotted visually by the derrick man at the shale shakers during lag time, or detected by the gas chromatograph on the mud logging

unit, and are the clearest indicators of having reached the reservoir. However, there may be shows at depths other than the pay zone due to near-balance conditions, migration, or minor hydrocarbon bearing layers that are not part of the main reservoir(s). Gas shows are differentiated from background gas due to their composition (gas chromatograph) and levels (measured in parts per million, ppm). Continuously detecting and analysing the gas brought to surface by the mud constitutes a large quota of the operational safety and kick prevention during drilling. For instance, gas percentage thresholds are set beforehand to operate the mud degasser, and to suspend drilling;

- Drilling breaks. This is an abrupt increase in Rate Of Penetration (ROP) that indicates a formation change, likely over-pressured sand (possibly hydrocarbon bearing). The higher pore pressure aids the crushing or scraping action of the drill bit. Note that the drilling break may also be a kick indicator during drilling; however, it is not a positive one. ROP variations are considered in conjunction with prognosed lithology, master logs from offset wells, other curves and trends, and cutting analysis;
- Shape and size of cuttings. After lag time, cuttings samples are collected at the surface and examined for lithology, fluorescence (hydrocarbon presence), and their shape and size give an indication of formation pore pressure and the amount of overbalance;
- Downhole pressure is measured in real time by a Logging While Drilling (LWD) tool. Other LWD tools include Gamma Ray, Sonic, Resistivity, and Neutron Density, which are available in real time and provide accuracy and resolution similar to conventional wireline tools. LWD is often used in deep water drilling as its cost is justified by offsetting the rig time required for open hole logging, to

be able to case long or unstable sections before stability problems arise, for geo-steering in horizontal wells in thin beds, or simply to increase confidence and operational safety during drilling (formation detection, downhole pressure measurement and management, and seeking superior performance);

- The relationship between ROP and hydrostatic differential pressure. D-Exponent and sigma-log provide direct measurement of the relationship between ROP and hydrostatic differential pressure (which in turn depends on mud weight and pore pressure). Maintaining a constant weight on bit (WOB), rotation per minute (RPM), and correcting for mud weights, a plot of incremental ROP defines an increasing trend in the normally pressured zone. The trend should reverse when drilling into an over-pressured zone;
- Mud salinity. Provided that a water-based mud is used, measuring the chloride content in the mud is a valid method for determining underbalance conditions, as salt water contained in the formation drilled can enter the well bore and cause an increase of chlorides in the mud. A similar concept applies to mud resistivity and PH;
- Mud temperature. Over-pressured shales contain a considerable amount of water, which acts as an insulant and prevents heat spreading uniformly from below. Mud temperatures are plotted against depth and the interpretation of the curve may lead to the detection of the over-pressured zone, which might correspond to the reservoir. This method is rarely used since the results are not always reliable.

Table 2 summarizes the operational performance indicators (OPI) for kick detection.

Table 2: List of operational performance indicators (OPI) related to G&G risk factors.

Kick detection OPI	Way of detection	Geological and Geophysical (G&G) risk factors				
		HC	Porosity	Permeability	HP/HT	Abnormal Pressure
Increase in flow rate	Rig instrumentation	X	X	X		X
Increase in pit volume	Rig instrumentation or visual	X	X	X		
Pump pressure decrease/pump stroke increase	Rig instrumentation/ pressure gauges	X	X	X		X
Depth	Rig instrumentation Mud logging records Directional Drilling survey Driller's pipe tally	X			X	X
Oil and gas shows	Visual observation Gas chromatograph Rig gas detectors	X	X	X		X
Drilling break/ increase in rate of penetration (ROP)	Visual observation Rig instrumentation Mud logging instrumentation Directional driller drilling parameters sheet	X	X	X		X
Cuttings analysis	Visual observation (derrick man, Company Man) Mud logging service	X	X			X
Real time downhole pressure (LWD)	BHA tools at an offset distance from bit, transmitted in real time but requiring QC and interpretation				X	X
Other LWD readings, i.e. gamma ray, neutron-density, resistivity tools	BHA tools at an offset distance from bit, transmitted in real time but requiring QC and interpretation	X	X	X	X	
Empirical relationship between depth and ROP	D-Exponent and Sigma-log, based on OPI's depth and ROP				X	X
Mud salinity	Mud checks (field mud engineer analysis)		X	X		X
Mud temperature	Mud logging sensor				X	X

The main OPI for kick detection during drilling (kick indicators) are instantaneous parameters such as rate of penetration (ROP), stand pipe pressure (SPP), mud returns at the flowline, and active mud pit levels. Redundancy is guaranteed by installing two or more independent sensors, typically one sensor connected to the mud logging unit and a similar sensor connected to the driller console. In modern deep-water Mobile Offshore Drilling Units (MODU), further redundancy is built into the rig by using two active sensors connected to the driller's console for each parameter. A typical example is mud pit levels: two sensors measure the same level and the averaged level between the two is displayed on the driller console. Should a sensor fail, the driller is alerted and the reading of the remaining sensor is displayed.

Static or dynamic flow checks, carried out preventively or when signs of near-balance/underbalance are observed, if positive (well flowing), are generally considered as a positive kick indicator. However, there have been occasions when low volume and gradual influx were not detected in low permeability formations (possibly mistaken for the U-tubing effect if the flow check time is short, i.e. suspended before 30 minutes), and shut-in pressures were not read upon preventive closure of the BOP, which is caused by low accuracy of the pressure gauges at a few hundred psi over a scale of 5,000 or 10,000 psi (Ahmed, Hegab, & Sabry, 2016). In other instances, apparent positive flow-checks were related to ballooning formations, where fluid was stored in natural fractures or a slight deformation of the borehole and was returned by rock elasticity when the mud pumps were turned off.

It should be noted that an increase in background gas over time may indicate an increase in pore pressure or the penetration of a reservoir, whereas connection gas (detected once bottoms up is circulated after a Drill Pipe connection) and pump-off gas readings (when the pumps are off and the ECD is equal to the static MW, allowing influx to enter the borehole in case the well is in a nearbalance condition) indicate underbalance or near-balance conditions (Ahmed et al., 2016)

The indicators can be divided between instantaneous and lagged, according to the time required for identification. Instantaneous drilling parameters such as ROP, pump pressure, flow returns, and pit levels provide an immediate indication of the presence of a kick, whereas lagged indicators such as gas readings may indicate underbalance conditions. The mud circulated out of the bit carrying formation gas that it comes into contact with is only analysed once it arrives at surface, and lag time in deep wells may well be over 60 minutes. Increases in gas readings are an important tool for early kick detection as they indicate near-balance conditions hours before a kick occurs, at a point in time when a flow check would be negative and shut-in pressures zero, but drilling another stand with the same mud weight could lead to a kick. Logging While Drilling (LWD) readings are also considered to be lagged indicator since the sensor offset is typically around 15m from the bit and the data often needs quality checking and/or processing before it can be considered meaningful and reliable.

Ahmed, Hegab, & Sabry (2016) recommend a number of mitigation measures related to equipment and procedures that may help with early kick detection before it escalates to a more serious kick or a blowout. When a kick is suspected, a flow check should be made for no less than 30 min before it is judged negative, and through the trip tank for better accuracy and to enable the mud logging service to record it. Even in the case of a negative flow check, it is worth investing the time required for bottom-up circulation, to probe the gas levels of the mud that was in contact with the last formation drilled and assess the hydrostatic balance. Furthermore, additional pressure gauges with a smaller scale (hence higher accuracy at low pressures) should be installed at the choke manifold, to prevent minor influxes from going undetected upon shutting the well in, such as during a condition of slight underbalance.

2.3.3 Blowout Preventer Systems

The last blowout safety barrier and the main safety equipment used in oil well drilling operations is the Blowout Preventer (BOP), and the specifications of this system's working conditions on are based on: (i) the pore pressure gradient and (ii) the estimate of the density of a potential influx in the well (oil and/or gas).

The main BOP safety function is to close-in and control the unintended influx of reservoir energy that can occur during well operations. The subsea BOP system is made up of three main subsystems to achieve this function (Deepwater Horizon Study Group, 2011) (Strand & Lundteigen, 2015):

- The control system that distributes hydraulic power fluid from the hydraulic power unit and accumulator banks used for activation of the BOP closure elements. Modern control systems are based on two principles; electro-hydraulic ('multiplex') or pilot hydraulic ('all hydraulic').
- The Lower Marine Riser Package (LMRP) that provides the ability to connect and disconnect the drilling riser (connected to the rig) from the BOP stack (connected to the subsea wellhead). For example, in bad weather conditions or in a 'drive-off'/ 'drift-off' situation with a dynamically positioned (DP) rig.
- The BOP stack that connects to the wellhead and is made up of a 'stack' of BOP elements for well shut-in, acting within ca. 30-60 seconds when activated in different well control situations (i.e. different tubular sizes and well pressures).
- The BOP operation mode depends on how the elements are triggered. For example, using a Remote Operated Vehicle (ROV) the intervention is direct;

however, that is a contingency as it requires time to deploy the ROV. The standard procedure entitles the driller to use the BOP control panel and/or the emergency shut-down system (ESD) (Strand & Lundteigen, 2015).

The BOP system's layout and specifications are rig and well-specific; however, industry standards provide clear guidelines on their design (BSEE, 2014) and testing requirements (API, 2012).

A Technical review detailed by Strand & Lundteigen (2015), identified seven distinct BOP well isolation (close-in) scenarios that vary in accordance with the drilling stage, drilling technique and the arrangement of: drill string position and spacing, pressure, well geometry, and kick tolerance/fracture gradient. Kick tolerance is the maximum amount of influx of certain density that would cause the weakest formation interval to fracture. The characteristics of the BOP that impact its reliability aspects, such as being a system activated under demand and testable overtime, are investigated by several studies (Cai, Liu, Liu, Tian, Dong, et al., 2012; Cai, Liu, Liu, Tian, Zhang, et al., 2012; Strand & Lundteigen, 2015) and will not be detailed in this paper. The important characteristic of the BOP system that should be highlighted for the purposes of this paper is that such system change from rig to rig and are also a function of the well design.

3 METHODOLOGY AND ASSUMPTIONS

The methodology adopted to develop the blowout accident precursor risk model is a further development of the three-level modeling guideline suggested by Perez & Tan (2017), which is based on achieving the following objectives:

- **Objective 01**: Reflect specific risks in the function of the well drilling phase and well operations.

- **Objective 02:** Model specific design and operational conditions of safety barrier systems (top side and well) that affect the failure probability of these systems.
- **Objective 03:** Identify risk influencing factors (RIF) that affect the performance of the safety barrier elements.

The following work plan is proposed for designing the blowout risk model in accordance with the previously mentioned objectives, assuring the integration of: basic causes, safety barriers, Risk Influencing Factors (RIF) and Operational Performance Indicators (OPI). The specific guidelines related to each step of the work plan are provided later, and the model designed in accordance with the guidelines is presented in the following section (Section 4, Results).

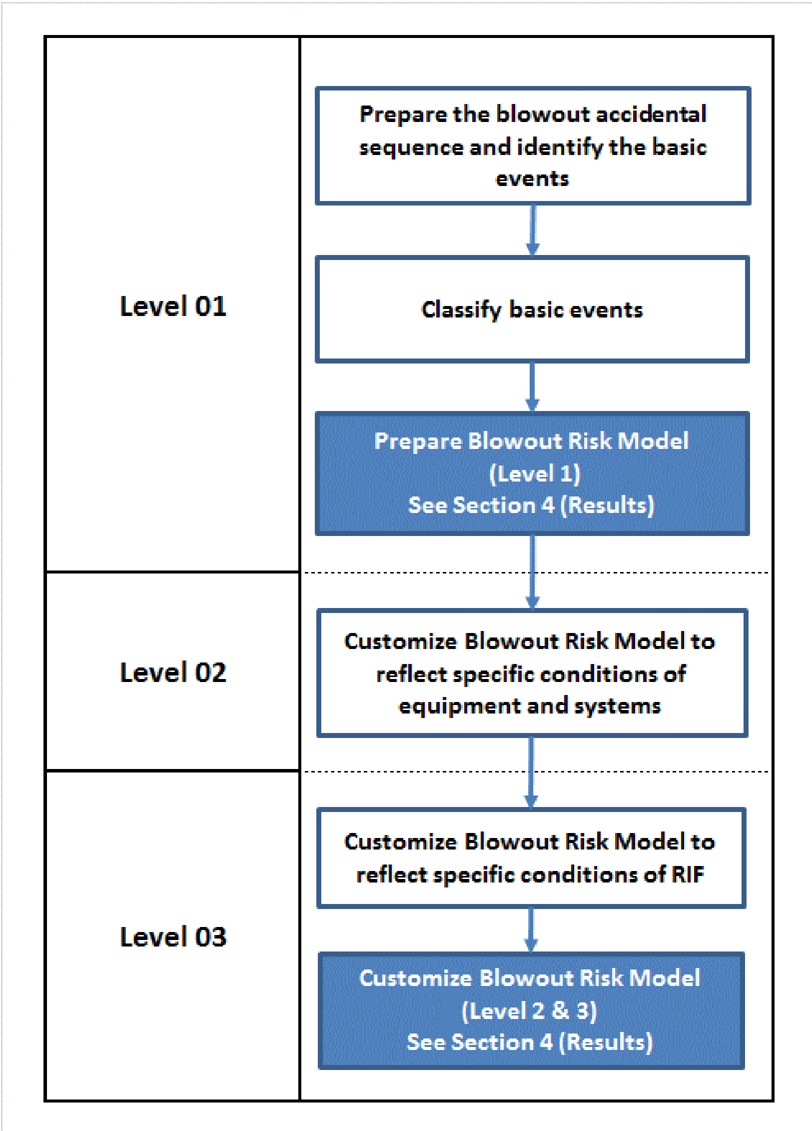


Figure 2: Workflow for developing the blowout model.

3.1 Prepare Blowout Accidental Sequence and Identify its Basic Events:

The blowout accidental sequence must reflect a specific drilling phase of a project. Examples of specific drilling phases exposed to blowout hazards are: a blowout while drilling into the reservoir, a blowout while tripping out of the hole and a blowout while drilling into over pressure zones or shallow hazard areas.

The mapping of the simplified accidental sequence and identification of the basic events of the model were based on a review of drilling and blowout concepts, which was summarized in Section 2, and considered contribution from the following research papers: (Xue, Fan, Rausand, & Zhang, 2013) who presented a safety barrier-based accident model for offshore drilling blowouts, and; (Nima, Khan, & Amyotte, 2013) who proposed a Bayesian approach for blowout risk modelling.

The basic events were identified depending on the simplified accident sequence model, which considers the kick as the top event, as the kick is the major blowout accident precursor.

3.2 Classification of the basic events:

The classification of safety barriers is an important step since it allows the characteristics of each element of the model to be understood and addressed. This classification was performed in accordance with Sklet (2006). The risk influencing factors (RIF) related to hardware (Technical Factors – TF) and human and organizational factors (HOF), and their related operational performance indicators (OPI), were identified in line with drilling safety indicator areas of influence suggested by Skogdalen, Utne, & Vinnem (2011), which was based on experience from the Macondo blowout.

Accordingly, the basic events (E_n) were classified in accordance with the three following concepts: barrier element, barrier system and risk influencing factors (RIF) related to geological and geophysical (G&G) conditions of the reservoir. The purpose of this classification is to separate the basic elements of the model into three distinct levels, to provide specific modelling considerations that will allow the blowout model to be customized for specific drilling projects (Step 4).

The general definition of safety barriers in the context of this paper is in accordance with Sklet (2006). This author defines safety barriers as physical and/or non-physical measures planned to prevent, control or mitigate undesired events or accidents. The measures may range from a single technical unit or human actions, to a complex socio-technical system. In line with ISO 13702 (2015), prevention means reducing the likelihood of a hazardous event, control means limiting the extent and/or duration of a hazardous event to prevent escalation, while mitigation means reducing the effects of a hazardous event. For the purposes of this paper, all safety barriers are considered preventive, considering that the focus is on protecting the crew from a possible blowout and not on the mitigation of further potential consequences.

Additional definitions from Sklet (2006) were also adopted for this paper: barrier functions and barrier systems. Barrier functions describe the purpose of safety barriers or what the safety barriers should do to prevent, control, or mitigate undesired events or accidents. A barrier system is a system that has been designed and implemented to perform one or more barrier functions. A barrier system describes how a barrier function is realized or executed. If the barrier system is functioning, the barrier function is performed. A barrier element is a component or a subsystem of a barrier system that by itself is not sufficient to perform a barrier function, and risk influencing factor (RIF) stands for any factor, including human and organizational factors (HOF), capable of affecting the performance of the barrier function by affecting an element or a system.

Table 3 presents the classification guidelines derived from the definitions of Sklet (2006) that are used for categorizing the basic elements of the proposed model.

Table 3: Classification of the basic elements of the model.

Modeling Level	Basic Element	Guide for classification
1	Safety barrier element	Single piece of hardware or software for which failure data is usually available in failure databases. Hardware or software that was not considered a complex socio-technical system, for instance: zero or low degree of dependability with other elements and systems, little or no variation in terms of technology and arrangement.
2	Safety barrier system	Systems composed of a combination of barrier elements that may significantly change in accordance with the well or rig type, in terms of: the degree of dependability, the system's arrangement (redundancy), operational/ management practices and the technology of the specific barrier elements that comprises the system.
3	Risk Influencing factors	Risk influencing factors are external factors capable of affecting the blowout risk and can be divided into: geological and geophysical factors (G&G), human and organizational factors (HOF) or technical factors (TF).

Additionally, barrier elements and systems are classified according to their typology: hardware, socio-technical and human/operational barrier (**Figure 3**). This is a simplified classification also based on the work developed by Sklet (2006), who reviewed the basic concepts of safety barriers including their different classification processes. The purpose of classifying the barriers into these typologies is to facilitate identification of risk influencing factors (RIF), since different types of RIF will affect the performance of safety barriers depending on their typology.

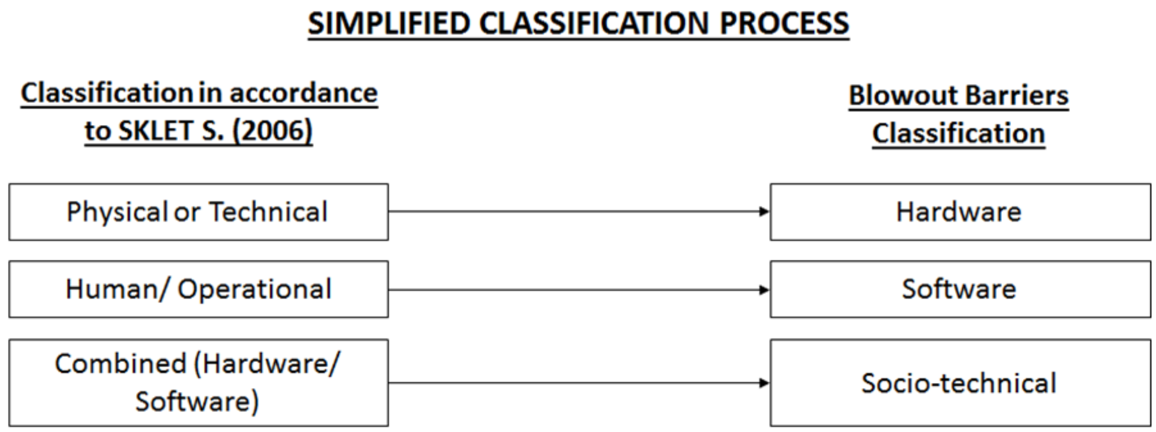


Figure 3: Proposed simplified safety barrier classification process.

3.3 Blowout Risk Model Design:

The blowout accident precursor risk model was designed by combining the following techniques: fault trees (to model the failure probability of sub-systems), event trees (to model the kick escalation into the blowout) and directed acyclic graphs (DAG) to account for the effect of the RIF on the performance of the safety barriers.

The top event of the bow-tie, which connects the fault tree to the event tree is the kick, as this is the blowout major accident precursor. Fault tree analysis (FTA) was adopted to model the logical relationship between the sub-systems that, in case of failure or given specific conditions, will lead to a kick. The escalation from the kick to the blowout wasmodeled using event tree analysis (ETA), modeling both the success (Y=Success) and failure (N=Failure) of the following systems responses: kick detection and activation of the blowout preventer.

It should be noted that the blowout risk is expected to change over time due to characteristics that are inherent to drilling activities. The regular operational changes over time (dynamic), as well as the blowout model characteristics limit the adoption of the bow-tie methodology as a unique modeling technique. Additional limitations are due to the lack of statistical data to quantify external risk influencing factors (RIF), human and organizational factors (HOF), and conditional dependencies (mostly between RIF), as demonstrated by Nima, Khan, & Paltrinieri (2014). Due to this inherent limitation, the bow-tie accident precursor model was complemented with directed acyclic graphs (DAG), with the purpose of mapping the cause and effect relationships between barrier elements and systems by using the groups of risk influencing factors (RIF) identified in this paper.

The failure of a barrier element or barrier system affected by a group of risk influencing factors (RIF) is represented in accordance with **Figure 4 (**Perez & Tan (2017)).

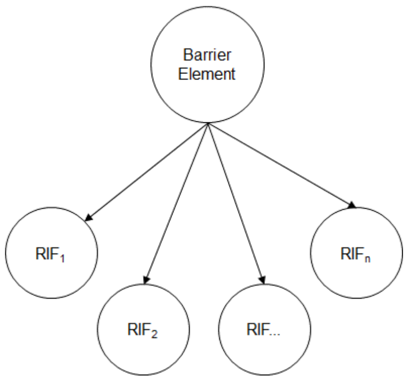


Figure 4: Bayesian network representation of failure of barrier element or system affected by a group of RIFs.

Equation 2 is a Bayesian inference obtained from the traditional Bayes theorem, with the purpose of calculating the posterior failure probability of a barrier element or system given the specific conditions of 'n' RIF:

$$P\left(\bar{E}\,|C_1, C_2, \dots, C_n\right) = P(\bar{E}) \times \prod_{i=1}^{n} \frac{P\left(C_i\,|\bar{E}\right)}{P(C_i)} \tag{2}$$

Bayesian inference derives the posterior probability as a consequence of two antecedents, a prior probability and a probability distribution which, in this case, is derived from observable data:

- $\mathrm{P}(\bar{\mathrm{E}} \mid \mathrm{C}_1, \mathrm{C}_2, \ldots, \mathrm{C}_\mathrm{n})$ is the posterior probability (Failure if TRUE and Operational if FALSE) of the barrier element or system given the influence of a specific group of risk factors $(\mathrm{C}_1, \mathrm{C}_2, \ldots, \mathrm{C}_\mathrm{n})$;
- $\mathrm{P}(\bar{\mathrm{E}})$ is the prior failure probability of a barrier element or system;
- P(Ci) is a probability distribution that represents the different possible observable conditions (states) of a risk influencing factor (Cn); and
- $\mathrm{P}(\mathrm{Ci} \mid \bar{\mathrm{E}})$ is the probability of a specific RIF given Failure (TRUE) or functionality (FALSE) of the barrier element, which can be expressed by the conditional probability table (CPT).

3.4 Customization of the Model to specific project conditions:

The customization of the model consists of implementing the work plan required for meeting the objectives of Level 2 and 3, which are:

- Calculating the prior failure probability of each safety critical barrier system by modelling the systems into its major basic elements, accounting for instrumentation technology, and for the elements' arrangement in the system and operational aspects of the system;
- Mapping potential interdependency between the safety barrier's systems;
- Identifying and mapping the group of RIF (Technical and HOF) affecting the performance of each safety barrier element;
- Correlating the RIF to the Company's Safety Management System (SMS) to allow verification of the adequacy of the RIF based on the most up-to-date information from: audit programs, inspections and KPI.

Section 4.2 provides a theoretical application that demonstrates the process of customizing the blowout risk model (Level 1) for the specific conditions of a drilling project (Level 2 and 3).

3.5 Assumptions

The assumptions made when developing the blowout risk model presented by this paper are:

- The model considers the scenario of a blowout while drilling into the reservoir in an exploration well;
- The rig is assumed to be a deep-water drilling rig, consequently with a sub-sea blowout preventer (BOP) and marine riser;
- The focus of the model is to prevent a blowout accident precursor event (kick/ losses), and on the modelling of the causal basic events in primary and secondary well barriers that could cause a breakdown in the escalation towards a well control situation. Failure during well control operations after closing the BOP and the escalation of the blowout to different scenarios are not part of this work;
- Since the focus is to detail the basic cause of the kick/losses, the model does not detail the different potential consequences of the blowout. However, for risk calculation, it can be assumed the worst-case scenario for Individual Risk Per Annum (IRPA), which is a constant exposure of the drilling crew and a fatality rate of 100% in the case of a blowout.

4 RESULTS

4.1 Blowout Risk Model (Level 1)

The basic events of the model were identified from the blowout escalation factors, which are defined as the factors that can contribute to the failure of the blowout primary and secondary barriers, are presented by the yellow boxes in **Figure 5**. These basic events, presented later in **Table 4**, were classified into: failures of barrier elements, failures of barrier systems or specific G&G risk factors that may directly contribute to the occurrence of the blowout.

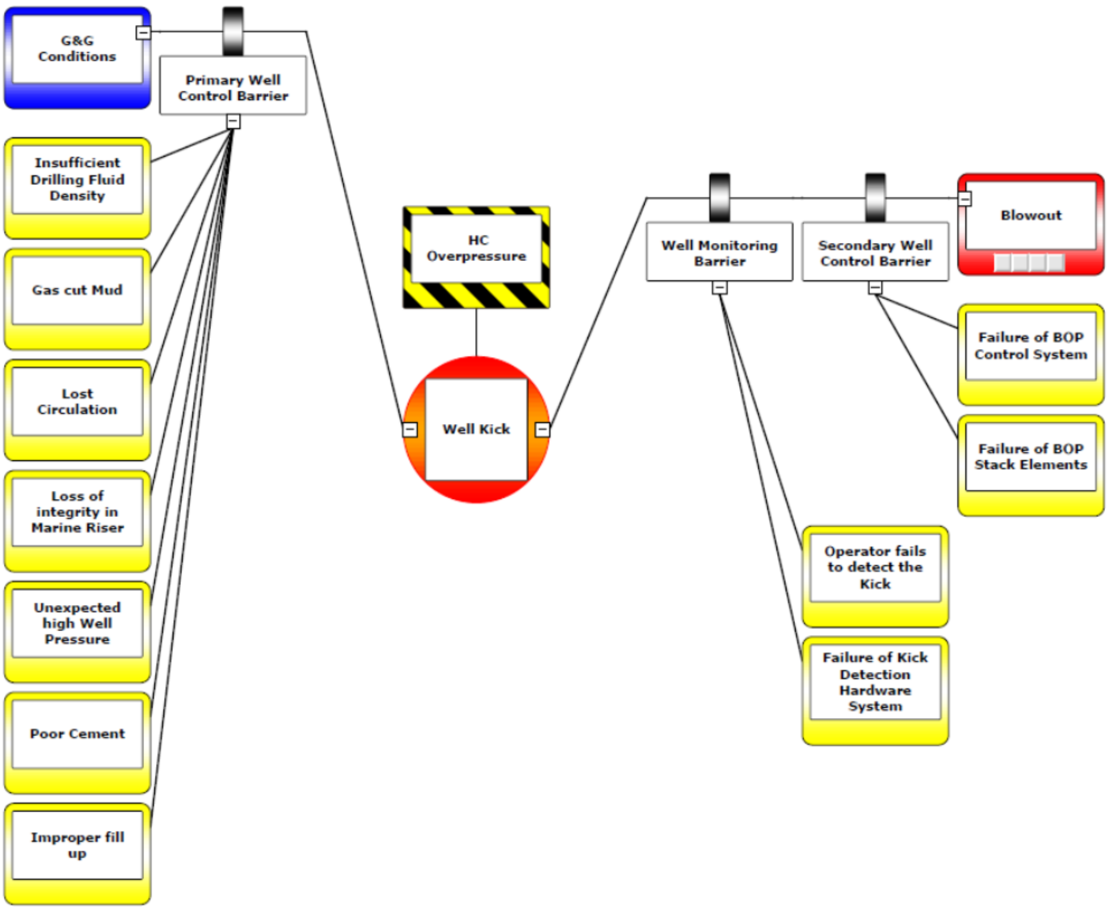


Figure 5: Accident precursor qualitative bow-tie diagram for a blowout event sequence.

From **Figure 5** it can be seen that the loss of the primary well control barrier (hydrostatic pressure imposed by the mud column pumped into the well), occurs when such pressure is exceeded by the reservoir pressure($p_h < p_r$). This can be caused by integrity failures, unexpected geological and geophysical (G&G) conditions, or failure in managing the mud pumped into the well (or a combination of these events). If the primary well control barrier fails, a kick will occur.

To avoid the escalation to a blowout, the blowout preventer (secondary well control barrier) must be activated to shut-in the well and, to activate the BOP, the kick must be identified in time (before hydrocarbons reach the BOP).

Table 4 presents a breakdown of the escalation factors displayed in the bow-tie diagram into the basic elements of the blowout risk model, as well as their classification in accordance with the guidelines presented in **Table 3** and **Figure 3**.

Table 4: Identification and classification of blowout basic events.

E_n	Basic Event	Barrier Element	Barrier System	G&G Risk Factor	Barrier Classification
E_1	G&G Conditions leading to loss of primary barrier			X	See **Table 2**
E_2	Well Integrity System (*)		X		Hardware
E_4	Density meter failure	X			Hardware
E_5	Human Failure (during mud preparation)	X			Human/ operational
E_6	Human Failure (during design of mud plan)	X			Human/ operational
E_7	Gas cut mud (mud weight affected by gas)	X			-
E_8	Mud weight temperature effects (HPHT)	X			-
E_9	Mud pump failure	X			Hardware
E_{10}	Pump control system failure		X		Hardware
E_{11}	Energy system failure		X		Hardware
E_{12}	Structural failure of marine riser	X			Hardware
E_{13}	Annular failure leading to losses	X			Hardware
E_{14}	Operator failure to detect the kick	X			Human/ operational
E_{15}	Kick detection hardware system failure		X		Hardware
E_{16}	BOP control system failure		X		Hardware
E_{17}	BOP stack elements failure		X		Hardware

(*) Well integrity system includes all hardware elements that vary in different phases of the drilling program and may include the combination of one or more of the following barriers: cement, casing, check-valves and plugs.

The classification of the blowout basic events shows that the blowout risk model combines all types of safety barriers as well as G&G risk factors, therefore it may be classified as a complex socio-technical system. As shown by Reason (1990), the operational reliability of complex socio-technical systems is dependent upon human operators as well as on the organization (procedures and management practices).

Skogdalen, Utne, & Vinnem (2011) suggested several operational indicators at the organizational and operational level related to deep-water drilling. These indicators are associated with typical safety management practices adopted in deep-water drilling and may be used for identification of risk influencing factors - divided into operational aspects and technical conditions - that affect the system during the operational phase. As a result, it is possible to correlate these RIF with the typology of the safety barriers of the socio-technical system, which in this case is the blowout risk model.

Table 5 presents the correlation between risk influencing factors (RIF) and operational performance indicators (OPI) with the different types of safety barriers as a function of their typology.

Table 5: Identification of Risk Influencing Factors (RIF) and typical Operational Performance Indicators (OPI) according to safety barrier typology.

RIF_n	Risk Influencing Factors	Examples of OPI specific for Drilling Blowout	Typology	
RIF_1	Competence and training;	- Kick drills performance indicator; - Well control competency indicators;	Software (HOF)	Socio-Techno Systems
RIF_2	Communication;	- Adequacy of record of reports related to well planning, drilling daily reports and operational meetings;		
RIF_3	Procedures (work practices);	- Adequacy of well control procedure to industry standards and rig/ well characteristics;		
RIF_4	Work schedule aspects;	- Work schedule in accordance to industry standards;		
RIF_5	Management and documentation;	- Reliability (Q/A) and availability of well plan and drilling program; - Adequacy of well plan and drilling program Management of Change (MoC);		
RIF_6	Installation and maintenance procedures;	- Adequacy of maintenance and equipment installation work orders and procedures to equipment/ systems' specifications;	Hardware (TF)	
RIF_7	Tests and inspections;	- Tests/ inspections executed as planned; - Results of tests/ inspections;		
RIF_8	Preventive maintenance;	- Preventive maintenance executed as planned; - Results of corrective actions;		

The barriers must be available and adequate for the design and operational conditions to guarantee the performance of the safety function. The effectiveness of the barriers is assessed by verifying their reliability and the adequacy of the risk influencing factors (RIF) that affect each barrier. The degree of adequacy for the RIF can be assessed based on industry standards and industry good practices that are generally measured by one or more of the OPI provided as examples in **Table 2** (for G&G risk factors) and **Table 5** (for human, organizational HOF and technical factors TF).

The blowout model resulting from this process is presented in **Figure 6** and combines the following modeling techniques: fault tree analysis (FTA), event tree analysis (ETA) and directed acyclic graph (DAG), which is the basis for Bayesian Network (BN) modeling. The model is composed of different symbols, as it combines not only different techniques but also different basic events from: barrier elements, barrier systems and risk influencing factors (HOF and G&G).

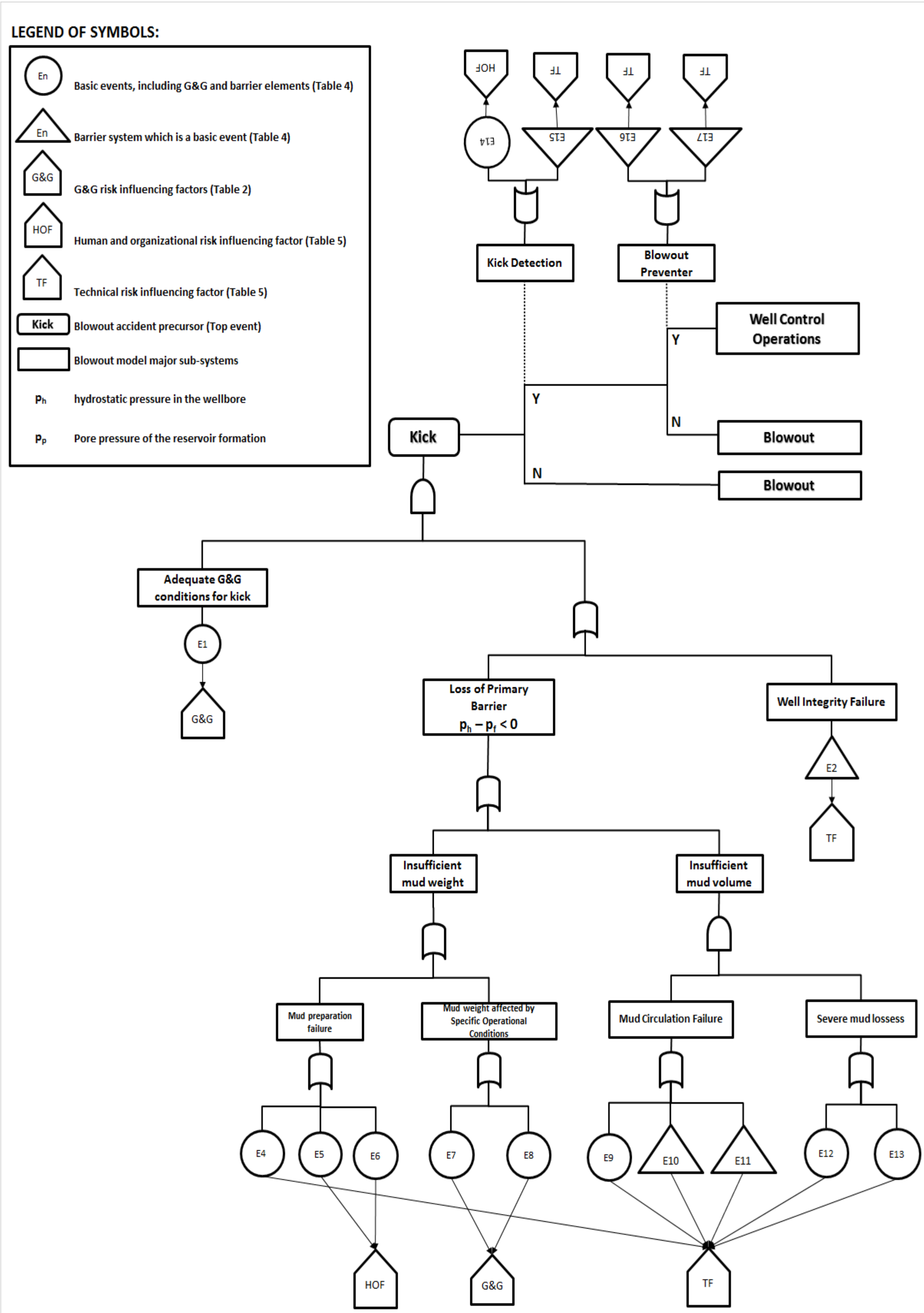


Figure 6: Blowout accident precursor risk model

From this mapping, it could be shown that the kick of a well will occur when geophysical and geophysical (G&G) conditions (hydrocarbon, pressure, permeability and porosity) are present (E_1), combined with the failure of the primary barrier. The primary barrier fails when the hydrostatic pressure in the wellbore is lower than the formation pressure ($p_h - p_p < 0$) or, in other words, when the mud weight pressure's gradient becomes lower than the formation pore pressure's gradient.

An alternative situation that may lead to the kick is when hydrocarbons migrate to the surface through the annular space due to failure of the well integrity system (E_2), which barrier elements and configuration strongly depend on during well design, the drilling phase, and well operations. For instance, pressure communication from the reservoir through a failed or channelled cement barrier, a failed casing pipe, connection, or liner hanger. Failure of the well integrity system constitutes the root cause of the two hypotheses of hydrocarbon flow paths generated by the Macondo blowout investigation (Deepwater Horizon Study Group, 2011).

The hydrostatic pressure in the wellbore is lower than the formation pressure ($p_h - p_r < 0$) when one of the following conditions are met: insufficient mud weight or insufficient mud level in the wellbore. Insufficient mud weight may result from several factors, including failure in preparing or designing the mud, or due to external factors related to G&G conditions that directly affect its weight. Insufficient mud level occurs when there are mud losses combined with failure to fill the well with mud, due to failure in the rig mud circulation system or unavailability of sufficient mud in the active and reserve tanks. The reliability of the mud circulation system may significantly change in accordance with: the number of mud pumps available and required to deliver mud to the wellbore and mud system components and controls. Failure of the power generation and distribution system may also lead to complete failure of the mud circulation system.

When a kick occurs, regardless of its causes, there is only one last barrier system that can stop it escalating to a blowout: the blowout preventers (BOP). The activation of the BOP depends of the success of the kick detection system and the BOP hardware system itself. The kick detection system is strongly dependent upon human and organizational factors (HOF) as it may fail either due to operator's error in interpreting pressure readings and well conditions data (E_{14}), or due to hardware not providing proper data to the operator (E_{15}), as presented in the simplified Technical Factors (TF) for the kick detection system. The BOP will fail when its activation control system fails (E_{16}) or, when the BOP stack components fail (E_{17}), is responsible for shutting-in the well and isolating the rig from the reservoir's energy.

In the blowout model the RIF were divided into the following groups:

- Geological and geophysical (G&G) risk factors: presence of hydrocarbons, porosity, permeability, high pressure/ high temperature (HP/HT) and abnormal pressure (**Table 2**);
- Human and organizational factors (HOF): RIF_1 (competence and training), RIF_2 (communication), RIF_3 (procedures), RIF_4 (schedule aspects related to human factors) and RIF_5 (management and documentation) – (**Table 5**);
- Technical factors (TF): RIF_6 (installation and maintenance procedures), RIF_7 (tests/ inspections), RIF_8 (preventive maintenance) – (**Table 5**).

Socio-technical systems are systems impacted by both technical and human and organizational factors – (**Table 5**).

4.2 Blowout Risk Model Customization (Level 2 & 3)

The first step for reflecting specific conditions of the drilling project and rig in the blowout risk model (**Figure 6**) is to detail the specific failure probability of the Level 1 barrier systems. This is done by modeling the barrier system into the specific barrier elements. The second step consists of identifying and correlating the RIF that may affect the performance of the barrier system's elements.

The BOP control system (E_{16}), a safety critical part of the BOP system, was chosen as an example of a safety barrier system. For the sake of simplicity, the BOP control system was simplified into the following major critical elements (Strand & Lundteigen, 2015):

- Main control system composed of two redundant BOP control panels;
- Independent dual control POD for operation;
- Hydraulic power unit and distribution system; and
- Accumulators that provide 'fast closure' (emergency mode) of the BOP components in the case of a loss of power fluid connection to the surface.

Table 6 presents the information required to break down a barrier system into its elements and meets the requirements related to the Level 2 objective.

Table 6: Level 2 Modeling spreadsheet example.

Level 2 Modeling Spreadsheet

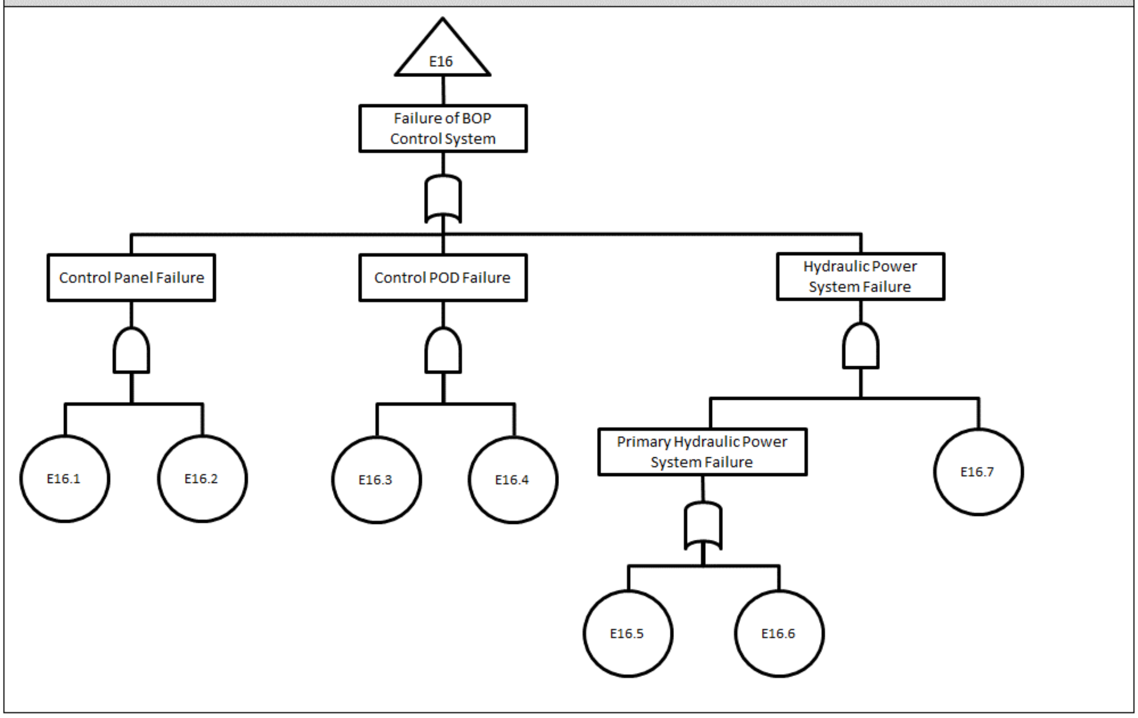
Drilling Rig:	Rig Name	**Well/ Location:**	Well name/ Location
Barrier System:	Blowout Preventer (BOP) Control System (Sub-system of the BOP)	**Safety function:**	Control system that distributes hydraulic power fluid from hydraulic power unit and accumulator for activating the BOP which safety function is to close-in and control unintended inflow of reservoir energy that can occur during the well operations.

SCS Identification	**Barrier Elements Register**					**Interdependencies with other SCS**
	ID	**Description**	**Prior Failure Probability**	**Redundancy**	**Model/ Type**	
E16	E16.1	Control panel 01	5%	100%	TBD	N/A
	E16.2	Control panel 02	5%	100%	TBD	N/A
	E16.3	Control POD 01	5%	100%	TBD	N/A
	E16.4	Control POD 02	5%	100%	TBD	N/A
	E16.5	Hydraulic power unit	5%	N/A	TBD	N/A
	E16.6	Hydraulic power distribution	5%	N/A	TBD	N/A
	E16.7	Accumulators	5%	N/A	TBD	N/A
E16 System Prior Failure Probability:			**1%**			

(*) TBD "To be Determined". Prior failure probabilities should be obtained from failure data banks or manufacturer data log. The values herein provided are for the purpose of exemplification.

(**) N/A "Not Applicable"

E16 - Level 2 Fault Tree



The next step consists of reflecting specific conditions of RIF in accordance with the methodology presented in the previous section. **Table 7** demonstrates a correlation between a customized barrier system and an applicable group of RIF. The group of RIF in the example was defined in accordance with the correlations presented in **Table 5**: Identification of Risk Influencing Factors (RIF) and typical Operational Performance Indicators (OPI) according to safety barrier typology. The status column presents examples of observable information that can indicate the general adequacy (conditions) of RIF affecting each barrier element.

Table 7: Level 3: Risk Influencing Factors Spreadsheet example.

Level 3: Risk Influencing Factors Spreadsheet (Example for Barrier System E16)

SCS ID	Type of RIF	ID	Group of RIF (Examples)	OPI in SMS (Examples)	Where / How to verify adequacy?	Status (Examples)
E16	Technical Factors (TF)	E16.1	Installation and maintenance procedures;	Adequate maintanence procedures	Documentation audit	Adequate
			Tests and inspections;	Results of tests/ inspections	Rig Maintenance System	Functioning
			Preventive maintenance;	Preventive maintenance on schedule	Rig Maintenance System	Delayed
		E16.2	Installation and maintenance procedures;	Adequate maintanence procedures	Documentation audit	Adequate
			Tests and inspections;	Results of tests/ inspections	Rig Maintenance System	Functioning
			Preventive maintenance;	Preventive maintenance on schedule	Rig Maintenance System	Delayed
		E16.3	Installation and maintenance procedures;	Adequate maintanence procedures	Documentation audit	Adequate
			Tests and inspections;	Results of tests/ inspections	Rig Maintenance System	Not Functioning
			Preventive maintenance;	Preventive maintenance on schedule	Rig Maintenance System	On shedule
		E16.4	Installation and maintenance procedures;	Adequate maintanence procedures	Documentation audit	Non-adequate
			Tests and inspections;	Results of tests/ inspections	Rig Maintenance System	Functioning
			Preventive maintenance;	Preventive maintenance on schedule	Rig Maintenance System	Delayed
		E16.5	Installation and maintenance procedures;	Adequate maintanence procedures	Documentation audit	Non-adequate
			Tests and inspections;	Results of tests/ inspections	Rig Maintenance System	Functioning
			Preventive maintenance;	Preventive maintenance on schedule	Rig Maintenance System	On shedule
		E16.6	Installation and maintenance procedures;	Adequate maintanence procedures	Documentation audit	Adequate
			Tests and inspections;	Results of tests/ inspections	Rig Maintenance System	Functioning
			Preventive maintenance;	Preventive maintenance on schedule	Rig Maintenance System	On shedule
		E16.7	Installation and maintenance procedures;	Adequate maintanence procedures	Documentation audit	Adequate
			Tests and inspections;	Results of tests/ inspections	Rig Maintenance System	Functioning
			Preventive maintenance;	Preventive maintenance on schedule	Rig Maintenance System	On shedule

The information presented in both Tables is mapped into a Bayesian Network (BN), which allows probability updating in accordance with the verifications provided in the “Status” column of **Table 7.**

Figure 7 presents the BN constructed in accordance with the methodology presented in the previous section. The following assumptions were adopted for the sake of simplicity and demonstration:

- Prior failure probability of barrier elements were considered 5%; and
- A simplified conditional probability table (CPT) was provided in **Figure 8**. The only purpose of the CPT is to reflect the belief that failure probability will decrease when the OPI of each RIF is considered to be compliant and will increase

when they do not comply with pre-defined conditions of operations and design specifications.

- The results from test and inspections (Operational/ Failure) provide direct updates on the status of the barrier element and not on the RIF condition.

Table 8: CPT explained for demonstration.

Possible States of Barrier Element ($E_{16.n}$)	**Barrier Element status**	
	Operating	**Failure**
Adequate or On-schedule	0.9	0.2
Non-adequate or Delayed	0.1	0.8

Figure 8 in the sequence presents the BN updated in accordance with the observations registered in **Table 7**.

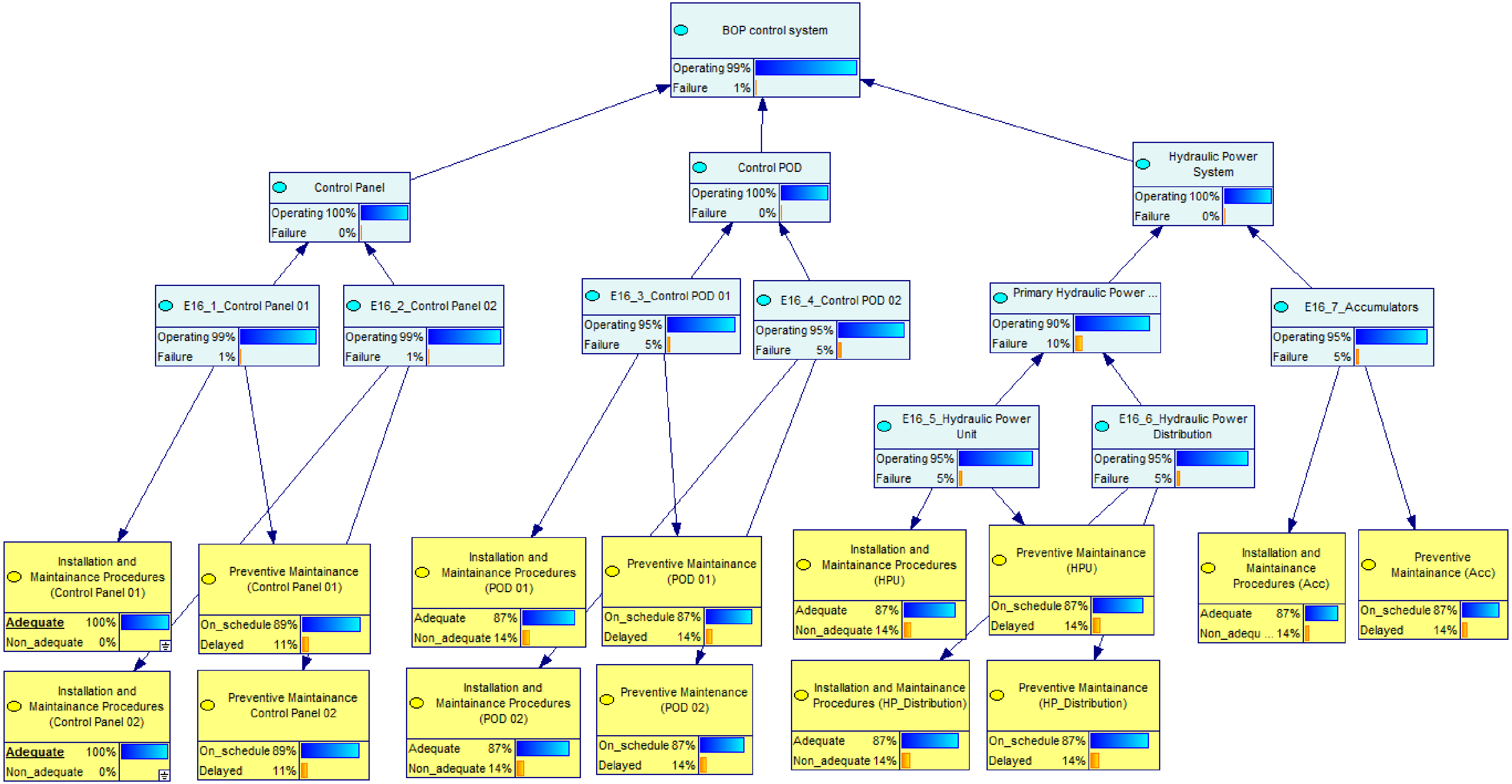


Figure 7: Bayesian Network for consolidating Level 2 with Level 3 spreadsheets (Non-updated Probability).

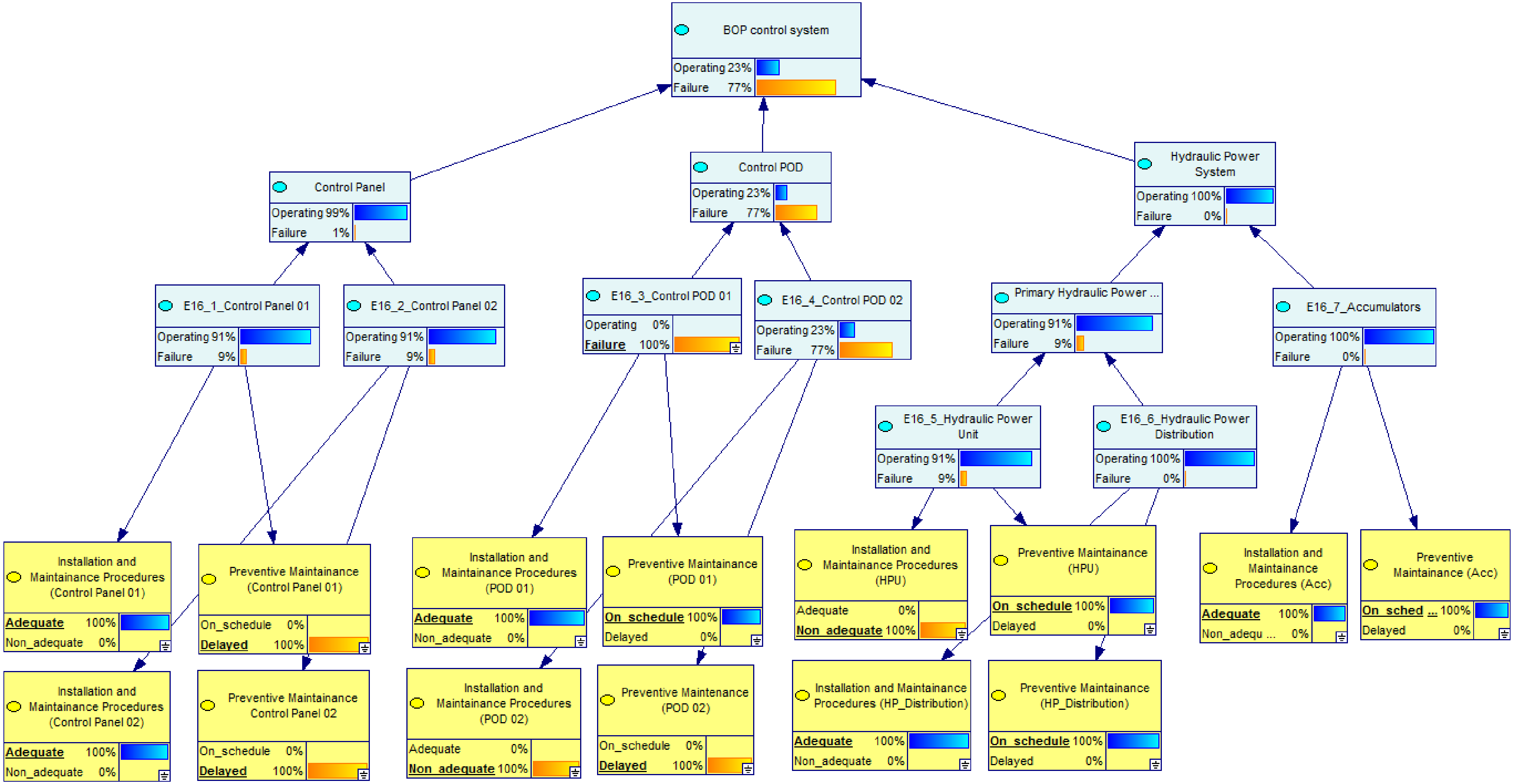


Figure 8: Bayesian Network for consolidating Level 2 with Level 3 spreadsheets (Updated Probability).

The performance of the BOP control system is affected by the conditions that were defined for the RIF affecting the barrier elements of the system, in accordance with the example provided in **Table 7**. The failure probability of the system raised from 1% to 77%, a significant variation for a major sub-system of a safety critical system (BOP).

5 CONCLUSION

Offshore drilling is a complex and risky activity, the safety of which depends on the reliability of a complex socio-technical system, which is a combination of technical and non-technical systems. The modeling method demonstrated by this paper, based on the three-level modeling guideline from Perez & Tan (2017), has been shown to be efficient in integrating all the elements of this kind of singular socio-technical system: operational performance indicators (OPI), risk influencing factors (RIF), barrier elements and safety critical systems.

The blowout model that was designed in accordance with the method reinforced that, in order to mitigate the risks of blowout in deep-water drilling, the following aspects must be closely monitored and controlled: G&G risks factors, and the adequacy of risk influencing factors (not only related to hardware maintainability elements but also related to human and organizational factors (HOF) and processes).

The demonstration of the customization process of the barrier system (E_{16} BOP Control System) for meeting Level 2 and Level 3 requirements provided practical tools (**Table 6** and **Table 7**) that can be replicated for customizing the entire model to reflect the specific conditions of any drilling project. Also, it illustrated how the specific conditions of the barrier elements that compose a system can affect the system's reliability, under the assumption that external mechanisms affect its performance.

Consequently, it is shown that designing and implementing a risk-based plan focused on monitoring and maintaining the ideal performance of the elements of this model will drive down the risk of blowouts and contribute to the improvement of operational risk-based decision-making processes.

6 LIMITATIONS OF THE RESEARCH AND FUTURE WORK

The limitations of this work that should be highlighted are:

- The limited comprehensiveness of the model, as it was only designed to cover the major elements of Level 1. The customization to Level 2 and 3 was applied only to an example for a BOP Control System; and
- The lack of or limited access to statistical data for incorporating blowout risk influencing factors (RIF) into the quantitative risk analysis QRA, including the ones related to geological and geophysical (G&G) aspects and human and organizational factors (HOF) relevant to drilling.

From the previously mentioned limitations, the following future research has been suggested:

- Test the suitability of different methods for incorporating RIF into QRA, with a focus on the characteristics of blowout drilling. Some relevant methods include: BORA Release (Aven, Skelet, & Vinnem, 2006; Skelet, Aven, & Vinnem, 2006), Risk OMT program (Vinnem, Bye, Gran, Kongsvik, & Nyheim, 2012) and APPM (Perez & Tan, 2018);
- Customize the blowout risk model proposed by this paper to reflect the conditions of a full scale project, by implementing the customization guidelines for safety critical systems, risk influencing factors (RIF) and operational performance indicators (OPI).

7 ACKNOWLEDGMENTS

We would like to thank Witt O’Brien’s Brasil and Pemex Exploration and Production for partially sponsoring this work, and most of all: Adriano Ranieri, Greg Fenton, Flavio Andrade, Dr. Faustino Fuentes Nucamendi and Eduardo Zavala Nacer. Thanks also to Mr. Thiago Molina for providing his expertise on latest generation Deepwater MODU's, which enabled to add current and practical aspects to the academic research on kick detection and well control issues.

Abbreviations

BHA	Bottom hole assembly
BOP	Blowout Preventer
BORA	Barrier and operational risk analysis
DAG	Directed acyclic graph
DP	Dynamically positioned
ECD	Equivalent Circulating Density
G&G	Geological and Geophysical
HC	Hydrocarbon
HOF	Human and organizational factors
HP/HT	High Pressure/High Temperature
HSE	Health, Safety and Environment
IADC	International Association of Drilling Contractors
IMO	International Maritime Organization
IRPA	Individual Risk Per Annum
ISM	International Safety Management Code
ISO	International Standard Organization

LMRP	Lower Marine Riser Package
LWD	Logging While Drilling
MODU	Mobile Offshore Drilling Units
OPI	Operational performance indicators
OPI	Operational performance indicators
RIF	Risk influencing factors
ROP	Rate of penetration
ROV	Remote operated vehicle
RPM	Rotation per minute
SINTEF	Stiftelsen for industriell og teknisk forskning or " The Foundation for Scientific and Industrial Research"
TF	Technical Factors
WOB	Weight on bit
WOC	Weight on cement

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