POAC'15
Trondheim, Norway

Proceedings of the 23rd International Conference on
Port and Ocean Engineering under Arctic Conditions
June 14-18, 2015
Trondheim, Norway

WELL CONTROL OPERATION IN THE ARCTIC OFFSHORE: A QUALITATIVE RISK MODEL

Håvard Hegg Bergan[1], Masoud Naseri[1]
[1]Department of Engineering and Safety, University of Tromsø - The Arctic University of Norway, Tromsø, Norway

ABSTRACT
Oil and gas development in the Arctic is becoming a major focus in the industry today. However, compared to other regions, the less experience of drilling operations in the Arctic raises concerns about high-risk scenarios that might take place because of the harsh environmental conditions and their effects on operations, equipment, and human performance. In any offshore drilling setting, well control operations are among the most crucial activities taking place as failure to control the wellbore can lead to devastating scenarios such as oil spills, explosions, and major fatalities. There are mainly two safety barriers in place to prevent the loss of well control: primary and secondary well control barrier. The aim of this paper is to develop a qualitative risk model for a well control operation in the Arctic offshore. This aim is achieved by analysing the adverse effects of Arctic operating conditions on the causes and consequences of losing the primary and secondary well control barrier. Some risk reducing measures are then proposed based on such analysis.

INTRODUCTION
Despite the increasing trend of oil and gas activities in the Arctic offshore, there exist some major issues and challenges posed by the severe weather conditions and distinctive environmental features of the Arctic offshore, which need to be dealt accordingly. The Arctic offshore is characterized by harsh environmental conditions such as seasonal darkness, snowstorms, freezing temperatures, atmospheric and marine icing, different forms of sea ice and icebergs, dense fog, polar low pressures, etc. (Gudmestad and Karunakaran, 2012, Løset et al., 1999, Barabadi et al., 2013, NORSOK, 2007). Additionally, one should also consider the large variations in Arctic physical conditions. For instance, while the annual minimum air temperature in the southern Barents Sea varies from -9°C to -6°C, the northern parts experience an annual minimum temperature of -39°C to -20°C (ISO, 2010). Besides, there is a general lack of infrastructure in Arctic areas, where offshore operations normally take place at locations with long distances to shore. Such harsh operating conditions can result in reduced operational reliability and elevated risks associated with drilling activities (Naseri and Barabady, 2013, Barabadi and Markeset, 2011).

Qualitative and quantitative risk assessments are defined as "analyses that will assess causes for and consequences of accidental events, with respect to risk to personnel, environment and assets" (NORSOK, 2010b). Such assessments, if accounted for the adverse effects of Arctic operating conditions on drilling operations, can provide crucial information for the analysts to improve the operational reliability and safety by reducing the occurrence probability of the failures and severity of their consequences.

In terms of safety, well control operations are among the most important activities taking place in every drilling activity, as a complete loss of well control can result in a blowout leading to explosion, several fatalities, and major oil spills. In an overbalanced drilling, two barriers, known as primary and secondary well control barriers, are in place to prevent loss of well control. The primary well control barrier is referred to the mud column in the wellbore providing a hydrostatic pressure greater than formation pressure and smaller than formation fracture pressure, that prevents the influx of formation fluid into the wellbore. The secondary well control barrier is referred to securing the wellbore, using several valves that altogether form the blowout preventer (BOP) stack. The BOP stack acts as a redundant barrier if the primary barrier fails (Grace et al., 2003). If the wellbore is not secured within an appropriate time, a blowout may occur.

Several researchers (Xue et al., 2013, Abimbola et al., 2014, Khakzad et al., 2013, Abimbola et al., 2015, Cai et al., 2012) have analysed the risks associated with well control operations by analysing the causes and consequences of its different phases, including kick occurrence, BOP actuation, killing operation, etc. These studies, however, do not take into account the effects of operating environment. In the Arctic offshore drilling activities, the harsh operating environment can influence various phases of drilling activities, efficiency of well control barriers, and performance of drilling crew during killing operations, etc. In this regard, a risk model should be developed to account for such adverse effects on different elements and phases of well control operations.

The aim of this study is to present a qualitative risk model for the performance of the primary and secondary well control barriers considering the negative effects of Arctic operating conditions. For this purpose, different phases of a well control operation are discussed. The failure causes and consequences are identified using fault tree analysis (FTA) and event tree analysis (ETA), based on which a risk model is developed for the whole operation. The rest of the paper is organised as follows. The procedures and elements of the well control operation are reviewed and discussed, based on which a bowtie approach is selected to analyse various causes and consequences of unwanted events. The effects of Arctic operating conditions are discussed on different phases of the developed risk model. Concluding remarks are presented after discussing a number of risk reducing measures.

WELL CONTROL OPERATION PHASES

A well control operation is defined as a “collective expression for all measures that can be applied to prevent uncontrolled release of wellbore effluents to the external environment or uncontrolled underground flow” (NORSOK, 2010a). Well control operation can be discussed within different types of activities including drilling, completion, workover, production, and wireline operations, of which well control during overbalanced drilling of exploration wells is the focus of this study.

Maintaining a well under control can be achieved utilizing the functions of primary (i.e., mud column) and secondary (i.e., BOP stack) well control barriers. If the primary barrier fails to fulfil its function, an unwanted influx of formation fluid enters to the wellbore. This process is known as kick occurrence (Fraser et al., 2014). Secondary well control barrier must then be initiated that includes the discovery of the influx, containment, and circulation of the influx out of the wellbore using BOP stack (Grace et al., 2003, Khakzad et al., 2013). Thus, well control operations can be divided into four phases: kick prevention, kick detection, blowout prevention and killing operations, illustrated in Figure 1.

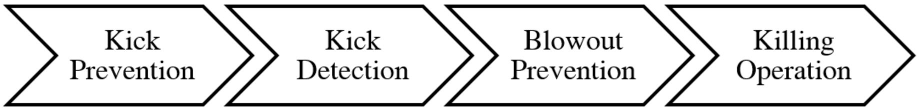

Figure 1. Well control operation phases (Khakzad et al., 2013)

DEVELOPING RISK MODEL FOR A WELL CONTROL OPERATION

A bowtie approach is selected to analyse the risks associated with well control operations. A bowtie diagram (see Figure 2) gives a clear overview of potential undesired scenarios, and is commonly used for process accident risk analysis (Khakzad et al., 2013). It consists of an unwanted event and a set of barriers for either preventing the unwanted event from occurring (i.e., active barriers) or mitigating the impacts if it occurs (i.e., passive barriers). Depending on the focus of the risk assessment, the unwanted event can be defined as a blowout or different phases of a well control operation. In this study, the bowtie diagram is adopted to analyse the performance of primary and secondary well control barrier, by taking each phase of a well control operation as an unwanted event. Thus, for each phase, a FTA and ETA are required to identify the causes and consequences of the failures of well control barriers in order, and thus to develop the overall risk model.

A fault tree is a graphic model that consists of logical interrelationships between different faults that can lead to the occurrence of the specified undesired event. Thus, by performing an FTA, one can identify the causes of an unwanted event and determine all the possible ways the unwanted event may occur (Stamatelatos et al., 2002, Vesely and Roberts, 1981). In an ETA, scenarios of successive events leading to hazard exposure and to undesirable consequences are modelled. The analysis utilizes event trees based on forward logic that propagate from an unwanted event through a chosen system, and consider all the potential ways the unwanted event can affect the system's behaviour. The system consists of subsystems or safety barriers, presented as event headings, which the tree proceeds chronologically through (Modarres, 2006). The outcomes of the event tree are dependent upon whether these barriers perform their intended functions.

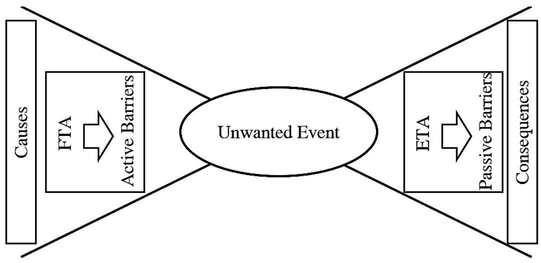

Figure 2. Illustration of a bowtie diagram, whose active and passive barriers are developed using FTA and ETA, respectively

Kick prevention

During an overbalanced drilling operation, kick prevention refers to the process of maintaining the wellbore pressure, which is supported by the weight of mud column, at a level higher than the surrounding formation pore and smaller than formation fracture pressure. If the formation pore pressure exceeds the wellbore pressure, formation fluid flows into the wellbore resulting in kick. Alternatively, if wellbore pressure is greater formation fracture pressure, drilling mud will be lost into the formation. This results in a reduced hydrostatic mud pressure below the formation pore pressure that consequently causes a formation influx into the wellbore. In general, the causes of a well kick can be categorized as: formation pore pressure greater than the mud weight; wellbore not kept full of mud while tripping; swabbing during tripping; loss of circulation; and presence of mud cut (Khakzad et al., 2013, Grace et al., 2003). Taking into account the causes of a kick occurrence, the corresponding fault tree model can be developed, as depicted in Figure 3.

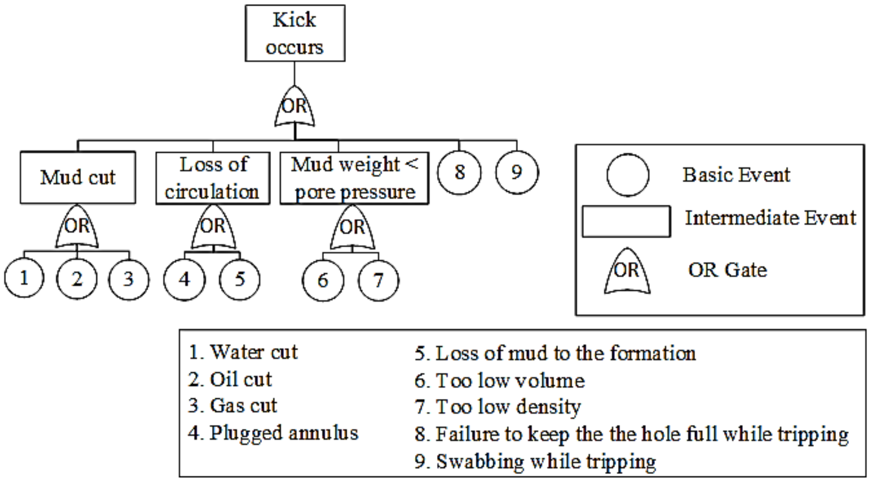

Figure 3. Fault tree for the kick event

Effects of Arctic operating environment on kick occurrence probability: In order to estimate kick occurrence probability in Arctic offshore drilling operations, one needs to account for the negative impacts of harsh environmental conditions on different causes of kick. As illustrated in Figure 3, causes of kicks can be related to either formation fluid properties, drilling fluid characteristics, failures in topside devices and facilities, and errors made by drilling crew. Although the Arctic environmental conditions may not influence the subsurface formation characteristics, they might have adverse effects of the remaining categories.

Low temperatures can adversely affect the rheological properties of drilling mud and lubricants (e.g., mud viscosity and gel strength), and mechanical properties of hoses and sealants (Caenn et al., 2011, Fink, 2012). Such adverse effects can increase the failure probability of pumps, gauges and devices mounted on trip tanks, based on which the operator keeps the well full while tripping, as well as hoses and connections.

The severe weather conditions can adversely influence the performance of drilling crew (Bercha et al., 2003). This may consequently result in, for instance, miscalculations of real-time swab pressure, failure of pumping drilling fluid into the wellbore while tripping, tripping in or out with a speed beyond the specified limit, etc.

Kick detection

If a kick occurs, it is of crucial importance that the kick is detected at an early stage to prevent its escalation. There are a number of common indications that a kick has occurred, including immediate increase in drilling rate, increased volume in the pit tank or increased flow rate, changes in pump pressure, and reduced drillpipe weight or weight-on-bit (Grace et al., 2003). An increase in drilling rate is an indication that a porous or fractured formation may have been entered, and thus there is a risk of underbalanced pressure (Khakzad et al., 2013). A rise in pit level in the mud or trip tank is likely to be a result of influx of formation fluid. This can also cause a decrease in pump pressure, as the hydrostatic pressure in the annulus will be lowered. Finally, as drilling mud is denser than formation fluid, an increased weight-on-bit will be experienced in case of a kick, due to the reduction in the buoyancy force (Grace et al., 2003).

A kick can be detected in its early stages by the use of several kick indicators. The primary kick indicators are principally flow-out sensors, installed to detect an increasing flow rate, and pit volume totalizer-sensors (PVTs), installed to continuously measure the present fluid level in the mud tanks (Fraser et al., 2014). Furthermore, while tripping, and when no circulation in the well takes place, trip tanks serve as accurate volume detectors. The increase in drilling rate, changes in the weight-on-bit, and deviations in standpipe pressure are detected by a number of topside gauges. Additional topside gauges are installed on the mud pumps to register the variations in pump pressure. Besides, some downhole tools, such as measurement-while-drilling (MWD) tools, can register the wellbore- and formation pore pressures and transfer the real-time information to the surface aiding the operators to maintain the overbalanced situation.

Such indicators can be considered as passive barriers to a well kick. Hence, an event tree model can provide essential information to analyse the performance of kick detection procedure. Figure 4 shows an event tree model developed for kick detection. To shut in the well, both the flow-out sensor and PVTs must indicate the possible presence of a kick. However, if the unwanted influx is larger than 10 barrel and detected by the PVTs, this will be a standalone indicator and the well should be shut in (Fraser et al., 2014).

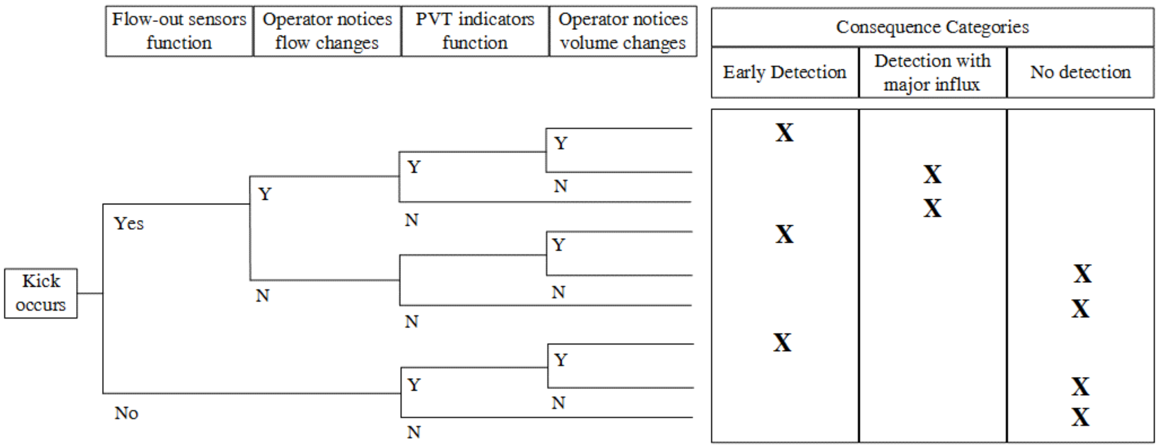

Figure 4. Event tree diagram showing the different consequence categories of kick occurrence

The potential outcomes of the developed event tree model are categorized into three groups: early detection, detection with some major influx and no detection. The early-detection category is when the kick has been detected in time and no major influx has entered the wellbore. Detection of the kick during the later stages with some major influx in the well occurs when the operator does not notice indications from the PVTs or that the PVTs fail to indicate the volume changes. In other words, additional time and additional indications are required for the kick to be identified. The last category involves the potential outcomes where the kick is temporary undetected. In this case, both indicators fail to fulfil their function or the operator fails to notice their indications. While a kick escalates without being detected, it migrates towards the surface due to its lower density. In lower depths, the reduction in hydrostatic pressure expands the kick and thus the mud hydrostatic head will be further dropped. This consequently results in the flow of more influx into the wellbore until it creates critical situations that might result in a blowout.

Effects of Arctic operating environment on kick detection probability: The elements and equipment that are located topside on the rig will be exposed to harsh weather conditions. Freezing temperatures that will be experienced during a drilling operation may alter material properties. Among others, high-strength steels, plastics and polymers become brittle when exposed to low temperatures (Singh, 2013, Barabadi and Markeset, 2011). If kick indicators and gauges are composed of such elements, fractures and structural cracks may occur. As transmitters might be sensitive to cold temperatures (Keane et al., 2013), the output signals from the gauges or detectors can be distorted. In addition, because of the large temperature variation in the Arctic, topside equipment can experience an additional strain (Larsen and Markeset, 2007). In cold temperatures, fluids will freeze and properties of hydraulic oils may change (Barabadi and Markeset, 2011).

Accretion of ice can reduce equipment accessibility, and potentially threaten the early kick detection. If, for instance, a pressure indicator has been exposed to severe atmospheric icing and the operator has to do a manual reading, some difficulties may arise due to reduced accessibility leading to late kick-detection.

As shown in Figure 4, early kick detection depends not only on the performance of flow-out sensors and PVT indicators, but also on the ability of the operators to notice changes in drilling parameters. Severe weather conditions can adversely affect the operator's cognitive and reasoning abilities (Larsen and Markeset, 2007). This may consequently lead to situations where the operator misses to read or notice the changes in drilling parameters or kick occurrence signs. In summary, all the passive barriers to kick detection can be affected by the Arctic operating environment.

Blowout prevention

Once a kick has been detected, the wellbore is shut in by actuating the BOP stack to prevent a blowout and to make a secure conduit for further killing operation. The BOP stack has a collection of at least four rams and typically one or two annular preventers (Cai et al., 2012). A BOP system also includes a control system required to manage the BOP stack and killing operation. The BOP control system consists of electric control system and fluid control system. The fluid control system includes pumps, valves, accumulators, fluid storage and mixing equipment, manifold, piping, hoses, control panels and other items necessary to hydraulically actuate the BOP stack. The electronic control system includes topside components that form the central control unit, subsea components, and umbilical cables responsible for transmitting the commands, initiated at the surface components, to the subsea control pods (Cai et al., 2012). In subsea control pods, the received signals are converted to hydraulic pilot signals and forwarded to specific hydraulic valves, which generate pressurized fluid required to close BOP valves (Shanks et al., 2003). At this step, when the well is shut in, formation fluids will enter the wellbore until the pressure in the well finally overcomes the formation pressure, i.e. regaining the overbalanced conditions while the well is kept shut in.

A reliable BOP system plays a crucial role in a successful well control operation. A fault tree model can be developed (see Figure 5), based on which one can assess the reliability performance of a BOP system, and identify the causes and their interactions that can lead to BOP system failure. The fault tree model, depicted in Figure 5, is developed for a typical BOP configuration that consists of two annular preventers, four ram-type preventers, choke and kill lines, choke and kill valves, and overall BOP control system.

As illustrated by the developed fault tree, a failure of choke and kill lines, as well as choke and kill valves can lead to a BOP system failure. In terms of annular and ram preventers, the BOP system may function if at least one annular preventer or ram functions properly. By connecting the annular and ram preventers by an OR-gate to the top event, this can be modelled. However, depending on the amount of escalated kick and its pressure, it might not be possible to shut in the wellbore safely, although an annular preventer functions. Thus, in emergency cases, one should actuate pipe or blind shear rams (Cai et al., 2012). In such scenarios, one may follow a conservative approach and, for instance, connect the failure in all the preventers by an AND-gate to the top event.

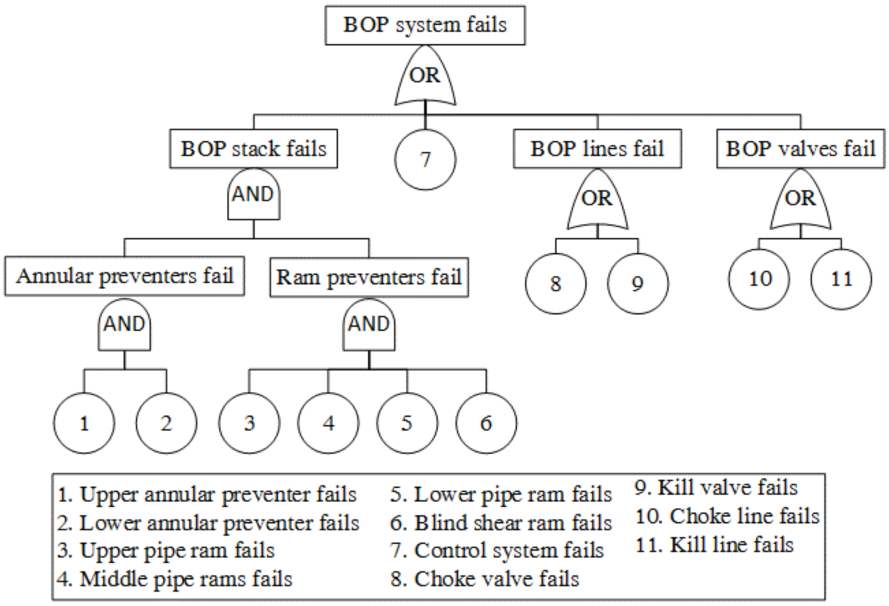

Figure 5. Fault tree for the failure of the BOP system

Effects of Arctic operating environment on blowout prevention: BOP stack is located on the seabed, and thus it is expected to be unaffected by the severe weather conditions experienced on the surface. Some elements of control unit system, such as driller's control panel, toolpusher's control panel, work-station, triple modular redundancy controllers, and connecting cables (Cai et al., 2012), however, are exposed to harsh Arctic operating environment, and thus their reliability performance may be adversely affected. Accreted ice on the floor and accumulated snow may limit accessibility to redundant control panels and thus reduce the reliability of BOP control systems. Atmospheric icing accreted on the connecting cables can exert additional loads, which may be asymmetric, that consequently can increase stress and fatigue rate, finally resulting in a shortened lifetime (Ryerson, 2011, NORSOK, 2007). Besides, as the actuation of the BOP preventers are performed by the operators, reduced human reliability under severe weather conditions can adversely affect the shut in procedure. Signal distortion in low temperatures (Keane et al., 2013) can also reduce the performance of the BOP control system, as it can affect the commands that are to be transmitted from the central control unit to the subsea control pods.

Killing operation

While the wellbore is shut in, the formation influx should be circulated out in order to regain the control of the wellbore by means of the primary well control barrier. The unwanted influx can then be circulated out through the choke line. The Driller's and the Wait and Weight methods are two common procedures for circulating the kick out of the well (Carlsen et al., 2013, Grace et al., 2003). The difference between these methods is about circulating out the kick using the mud that was in use or using the weighted mud. In Driller's method the formation fluids are circulated out by continuing to pump the drilling mud that was in use, while in Wait and Weight method, the wellbore is kept shut in until a weighted mud is prepared to start the killing operation (Grace et al., 2003).

A failure in killing operation can result in uncontrolled scenarios leading to devastating consequences. To have a reliable killing operation, one needs to identify all the contributing elements. First, BOP stack should be able to keep the wellbore closed until the operators start the killing operation. Once the kill mud is prepared and operators start the killing operation, BOP stack should be able to allow the operators to inject the kill mud at a specified injection pressure and rate, while the kick is being circulated out. For this purpose, in addition to BOP stack, the BOP control system must perform its desired function. Surface facilities, such as mud pump, hoses, mixing tanks, injection pressure and rate gauges, and all other equipment involved in a routine drilling operation, should be reliable, as well. Finally, killing operation is considered as an integrated task, which involves several members of drilling crew and requires their utmost attention on their specified tasks to prevent any operational mistake.

Effects of Arctic operating environment on killing operation: Brittleness of plastics, polymers, and metals, and changes in their mechanical behaviour can reduce the reliability performance of the equipment units, such as mechanical equipment, gauges, sensors, etc. Changes in temperature-dependent rheological properties of drilling mud and lubricants can damage the pumps, connections, hoses, lines, etc. Natural gas hydrates can form in low temperatures and high pressures when small gas molecules become entrapped in the cages of host clathrate lattices made of hydrogen-bonded water molecules (Gasson et al., 2013, Jamaluddin et al., 1991). This process may occur in gas cut mud, which is being circulated out from the wellbore and consequently lead to operational failures, corrosion, and safety hazards in solid control system.

Effects of being exposed to low temperatures, risks of falling ice, and slippery surfaces can increase human error probability and thus reduce the reliability of killing operation. Additionally, human performance can be negatively affected in cold temperatures combined with winds. For instance, low temperatures can make breathing difficult and thus lead to muscular stiffness. They can cause frostbites and hypothermia (Bercha et al., 2003). An operator's cognitive and reasoning abilities may be affected under these conditions, and cognitive errors are more likely to occur along with decreased work effectiveness and accuracy (Larsen and Markeset, 2007).

Loads imposed by accreted ice can damage shelter ceilings and result in equipment malfunction (Ryerson, 2011). Besides, the accumulated snow and accreted ice can reduce equipment accessibility leading to delays in operation tasks such as kill mud preparation.

The occurrence of polar low pressures can cause high waves, heavy snowfalls, icing storms, dramatic decrease in temperature, and sudden increases in wind speed (Gudmestad and Karunakaran, 2012). Such scenarios can considerably threaten the ongoing well control or killing operations.

The presence of sea ice and icebergs in the Arctic will be of concern during drilling operations, as there exist uncertainties regarding the calculation of ice-loads and load effects (Eik, 2011). If the drilling platform does not withstand the forces exerted by sea ice, an ongoing well control operation can be interrupted, leading to devastating scenarios. Furthermore, crushing ice sheets can induce platform vibration that can be harmful for rig structures, aboard equipment, and crew performance (Hou and Shao, 2014).

SUGGESTED RISK REDUCING MEASURES

The overall risk model for a well control operation can be obtained by combining its four phases using a bowtie diagram. Such model is illustrated in Figure 6 by considering the well kick as the unwanted event. Once a kick occurs, kick detection, blowout prevention and killing operation play as passive barriers to a blowout. However, as discussed the performance of such active and passive barriers can be negatively affected by harsh Arctic operating conditions. To cope for such effects, a number of risk reducing measures should be implemented.

Some of the factors contributing to an elevated risk can be overcome by winterizing the equipment units, which are likely to be affected by severe weather conditions. Winterization refers to the measures taken for the facilities to ensure an acceptable level of risk is achieved if such facilities are exposed to harsh weather conditions. This preparedness for cold climate conditions includes controlling the effects of icing, snow precipitation, low temperatures, and other Arctic meteorological characteristics (DNV, 2013).

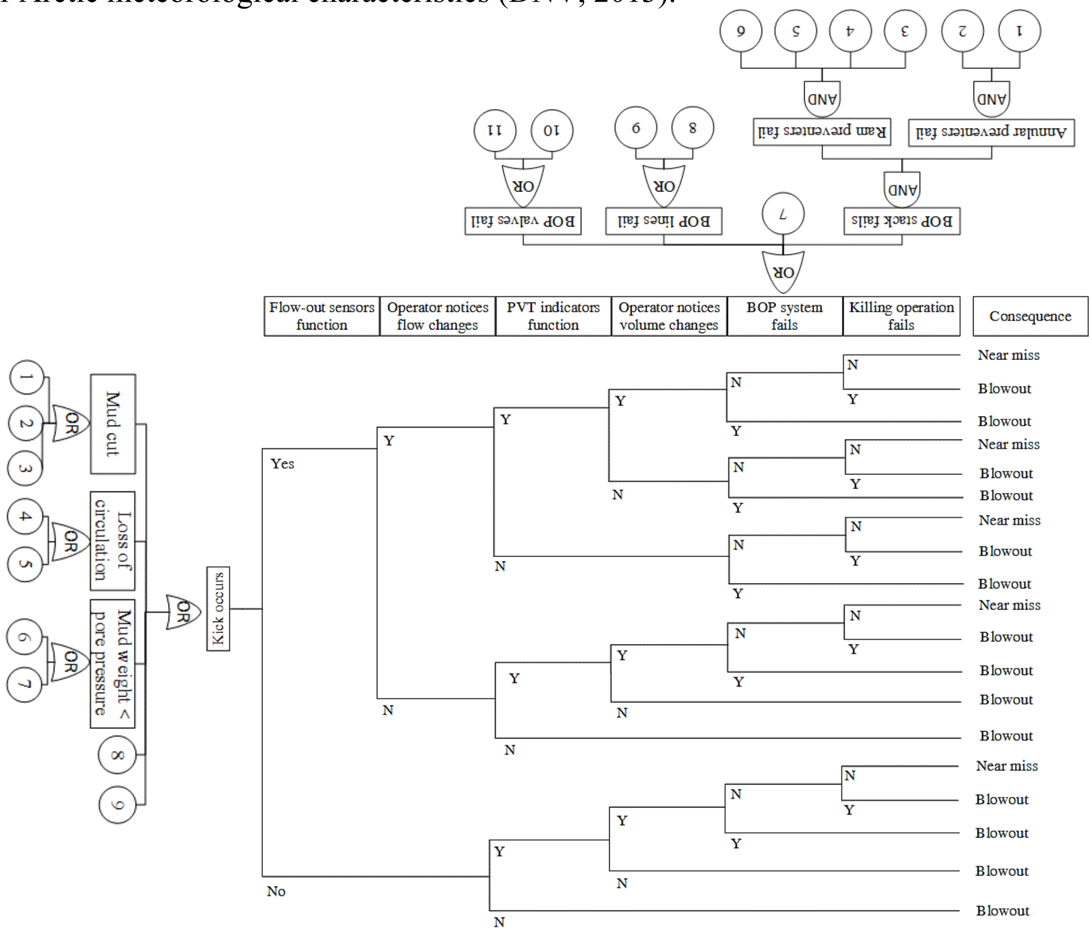

Figure 6. Overall risk model for a well control operation

For topside components, winterization may involve the use of an enclosure probably accompanied by installing internal heating elements (Gudmestad, 2010). Lack of complete enclosure or/and failure of heating elements can occur though, presenting potential scenarios of higher risks. Alternatively, using indicators, gauges, and alarms, which their function is independent of the cold climate conditions, is of great interest. In addition to winterization, adding redundancy can improve the reliability of the well control operations considerably. This can be implemented to kick indicators, control unit panels, BOP preventer and rams, transmitters, and cables. It should be ensured that in emergency cases all the required facilities and equipment are accessible.

Since early kick detection plays a crucial role in a successful well control operation, special considerations must be paid to the kick detectors with high reliability performance. Recent studies have proposed adding flow meters to the outflow side of the riser (Fraser et al., 2014). Not only will this improve the overall performance of the kick-detection safety barrier, but also it keeps some of the kick indicators away from the harsh surface conditions. Flow meters in the riser will detect the kick earlier than today's primary topside indicators can. In this case, flow meters will serve as redundant indicators that can confirm the flow rate deviations measured in the riser (Fraser et al., 2014).

Although some winterization measures may provide the operators with more convenient working conditions, there are still remaining stress factors affecting the operator's skill and reasoning capabilities. Training, optimising working shifts, and providing adequate clothing that can withstand the severe weather conditions and at the same time allow the crew to perform their required tasks conveniently, can be considered as measures to improve drilling crew performance.

DISCUSSION AND CONCLUSIONS

In this paper, a qualitative risk model was developed for a well control operation, by which different scenarios that can escalate a kick into a blowout were addressed. For this purpose, four main phases of a well control operation were identified and described by analysing the causes and consequences of primary and secondary well control barriers. Causes of a kick occurrence and BOP system failure were identified using fault tree models, while kick detection and killing operation scenarios were investigated using event tree models. The effects of Arctic operating conditions on different phases of a well control operation were discussed. Based on the qualitative analyses, it is concluded that the risk of a blowout in Arctic offshore drilling operations can be higher than the ones in the normal-climate conditions. The proposed model can base a foundation for identifying the elements of a well control operation that can be affected by the harsh Arctic operating environment. Based on such assessments, appropriate risk reducing measures can be introduced and applied. By implementing adequate winterization measures, the issues imposed by severe weather conditions on topside elements can be overcome. However, one must also consider the role of the human performance in well control procedures. On an overall basis, the human performance is considered poorer in the Arctic, resulting in an elevated probability of losing well control barriers.

REFERENCES

Abimbola, M., Khan, F. & Khakzad, N. 2014. Dynamic safety risk analysis of offshore drilling. *Journal of loss prevention in the Process industries,* 30.

Abimbola, M., Khan, F., Khakzad, N. & Butt, S. 2015. Safety and risk analysis of managed pressure drilling operation using Bayesian network. *Safety Science,* 76**,** 133-144.

Barabadi, A. & Markeset, T. 2011. Reliability and maintainability performance under Arctic conditions. *International Journal of System Assurance Engineering and Management,* 2**,** 205-217.

Barabadi, A., Naseri, M. & Ratnayake, R. M. C. Design for the Arctic Conditions: Safety and Performance Issues. Proceedings of the 32nd International Conference on Offshore Mechanics and Arctic Engineering - (OMAE), 2013 June 6-14, Nantes, France. American Society of Mechanical Engineers(ASME).

Bercha, F. G., Brooks, C. J. & Leafloor, F. 2003. Human Performance In Arctic Offshore Escape, Evacuation, And Rescue. *The 13rd International Ocean and Polar Engineering Conference.* 25-30 May, Honolulu, Hawaii, USA: International Society of Offshore and Polar Engineers (ISOPE).

Caenn, R., Darley, H. C. H. & Gray, G. R. 2011. *Composition and Properties of Drilling and Completion Fluids (Sixth Edition),* Boston, Gulf Professional Publishing.

Cai, B., Liu, Y., Liu, Z., Tian, X., Dong, X. & Yu, S. 2012. Using Bayesian networks in reliability evaluation for subsea blowout preventer control system. *Reliability Engineering & System Safety,* 108**,** 32-41.

Carlsen, L. A., Nygaard, G. & Nikolaou, M. 2013. Evaluation of control methods for drilling operations with unexpected gas influx. *Journal of Process Control,* 23**,** 306-316.

DNV 2013. Offshore Standard - DNV-OS-A201: Winterization for Cold Climate Operations. Det Nroske Veritas (DNV).

Eik, K. 2011. Sea-ice management and its impact on the design of offshore structures. *Cold Regions Science and Technology,* 65**,** 172-183.
Fink, J. K. 2012. Chapter 10 - Cement Additives. *In:* Fink, J. K. (ed.) *Petroleum Engineer's Guide to Oil Field Chemicals and Fluids.* Boston: Gulf Professional Publishing.
Fraser, D., Lindley, R., Moore, D. D. & Staak, M. V. 2014. Early Kick Detection Methods and Technologies. *SPE Annual Technical Conference and Exhibition.* 27-29 October, Amsterdam, The Netherlands: Society of Petroleum Engineers.
Gasson, J. R., Barth, T. & Genov, G. 2013. Comparison of the gas hydrate plugging potentials of a set of crude oils from the Norwegian continental shelf using chemometric decomposition of GC–FID data. *Journal of Petroleum Science and Engineering,* 102**,** 66-72.
Grace, R. D., Cudd, B., Carden, R. S. & Shursen, J. L. 2003. *Blowout and Well Control Handbook*, Elsevier
Gudmestad, O. T. 2010. Vessel winterization for cold climate operations. *5th Norway - Russia Arctic Offshore Workshop.* 16-17 June, Murmansk.
Gudmestad, O. T. & Karunakaran, D. 2012. Challenges Faced by the Marine Contractors Working in Western and Southern Barents Sea. *OTC Arctic Technology Conference.* 3-5 December, Houston, Texas, USA.
Hou, J. & Shao, W. 2014. Structural Design for the Ice-Resistant Platform. *The 24th International Ocean and Polar Engineering Conference.* 15-20 June, Busan, Korea: International Society of Offshore and Polar Engineers (ISOPE).
ISO 2010. ISO 19906: Petroleum and Natural Gas Industries – Arctic Offshore Structures. Geneva: ISO.
Jamaluddin, A. K. M., Kalogerakis, N. & Bishnoi, P. R. 1991. Hydrate plugging problems in undersea natural gas pipelines under shutdown conditions. *Journal of Petroleum Science and Engineering,* 5**,** 323-335.
Keane, B., Schwarz, G. & Thernherr, P. 2013. Electrical Equipment in Cold Weather Applications. *Petroleum and Chemical Industry Technical Conference (PCIC).* 23-25 Sep, Chicago: IEEE.
Khakzad, N., Khan, F. & Amyotte, P. 2013. Quantitative risk analysis of offshore drilling operations: A Bayesian approach. *Safety Science,* 57**,** 108-117.
Larsen, A. C. & Markeset, T. Mapping of operations, maintenance and support design factors in Arctic environment. *In:* AVEN, T. & VINNEM, J. E., eds. ESREL, 2007 Stavanger, Norway. London: Taylor and Francis Group, 2463-2470.
Løset, S., Shkhinek, K., Gudmestad, O. T., Strass, P., Michalenko, E., Frederking, R. & Kärnä, T. 1999. Comparison of the physical environment of some Arctic seas. *Cold Regions Science and Technology,* 29**,** 201-214.
Modarres, M. 2006. *Risk Analysis in Engineering: Techniques, Tools, and Trends*, CRC Press.
Naseri, M. & Barabady, J. 2013. Offshore drilling activities in Barents Sea: Challenges and considerations. *Proceedings of the 22nd International Conference on Port and Ocean Engineering under Arctic Conditions (POAC).* June 9-13, Espoo, Finland.
NORSOK 2007. NORSOK Standard N-003 - Actions and Action Effects. Lysaker, Norway: Standards Norway (NORSOK).
NORSOK 2010a. NORSOK Standard D-010 - Well integrity in drilling and well operations Lysaker, Norway: Standards Norway (NORSOK).
NORSOK 2010b. NORSOK Standard Z-013 - Risk and emergency preparedness assessment. Lysaker, Norway: Standards Norway (NORSOK).
Ryerson, C. C. 2011. Ice protection of offshore platforms. *Cold Regions Science and Technology,* 65**,** 97-110.

Shanks, E., Dykes, A., Quilici, M. & Pruitt, J. 2003. Deepwater BOP Control Systems - A Look at Reliability Issues. *Offshore Technology Conference.* 5-8 May, Houston.
Singh, R. 2013. Chapter 7 - Material Properties in Low Temperature Environment. *In:* Singh, R. (ed.) *Arctic Pipeline Planning.* Boston: Gulf Professional Publishing.
Stamatelatos, M., Vesely, W., Dugan, J., Fragola, J., Minarick, J. & Railsback, J. 2002. *Fault Tree Handbook with Aerospace Applications,* Washington, D.C., NASA Office of Safety and Mission Assurance.
Vesely, W. E. & Roberts, N. H. 1981. *Fault Tree Handbook,* Washington D.C., U.S. Nuclear Regulatory Commission.
Xue, L., Fan, J., Rausand, M. & Zhang, L. 2013. A safety barrier-based accident model for offshore drilling blowouts. *Journal of loss prevention in the Process industries,* 26**,** 164-171.