DEALING WITH RISK IN OFFSHORE DRILLING



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INTRODUCTION

The blowout, fire and sinking of the *Deepwater Horizon* in April 2010, with the tragic loss of 11 lives, together with a major pollution incident, put the issue of risk in offshore drilling operations into stark focus. Nevertheless, the demand for accessible and secure reserves of oil and gas will continue to present the industry and its insurers with technical and environmental challenges of increasing complexity against a background of intense political and public scrutiny. As with previous incidents, there will be lessons to be learnt, and the reassessment of risk, together with probable tightening of regulatory controls, will drive changes in technology and operating procedures.

DEVELOPMENT OF OFFSHORE DRILLING AND PRODUCTION

In the late 19th century, wells were drilled from piers extending out from the shore or from platforms piled into shallow water (for example, California, Louisiana, Lake Maracaibo, Baku).



Summerland Beach, California (Oil & Gas Journal)

The Kerr McGee well 'Ship Shoal No. 32', off the Louisiana coast, is heralded as the foundation of the modern offshore drilling industry. The well was drilled in 1947 from a platform off the Louisiana coast, using a converted naval barge as a drilling tender.

As drilling moved into deeper water, jack-up and submersible drilling units were developed. The first semi-submersible drilling unit (actually a submersible operating in floating mode instead of standing on the sea bed) appeared in 1961.



Ship Shoal No. 32, Gulf of Mexico (Oil & Gas Journal)

The development of jack-up and semi-submersible drilling units continued, and drillships were first introduced in the late 1950s. Some modern jack-up drilling units can operate in water depths in excess of 150 metres, while advanced semi-submersibles and drillships now have the ability to operate in water depths of greater than 3,000 metres.



Blue Water Rig No. 1 (Friede & Goldman Ltd.)

Semi-submersibles and drillships can be moored or dynamically positioned (DP). Those operating in extreme water depths (of more than 1,000 metres) are generally DP, although units have been moored successfully in water depths of greater than 2,500 metres (for example, Transocean *Deepwater Nautilus*).

In just over 60 years, about the same length of time since the development of commercial jet aircraft, the offshore drilling industry has built up the capability to drill in locations ranging from coastal shallows, swamps, rivers and lakes to pack ice, deep water and exposed locations subject to extreme weather conditions.

Whilst the basic processes of offshore drilling, well construction and completion have remained fundamentally consistent over this time, the technology has developed to a high degree of complexity and sophistication. Modern data acquisition and interpretation techniques take much of the guesswork out of the location of potential sources of oil and gas. There is still, however, no substitute for drilling, either to prove the existence of a reservoir or to develop it. Today's high-capacity drilling units, coupled with developments in drilling fluids, directional drilling, well logging and completions technology, enable the discovery and development of complex reservoirs in deep water and hostile environments.

. RISKS INHERENT IN OFFSHORE DRILLING AND PRODUCTION

Just as the aviation industry has had its tragic setbacks, such as the loss of the early De Havilland Comet airliners due to fatigue failure of the fuselage, the offshore industry has suffered a number of significant accidents with loss of life and equipment. In December 1965, the jack-up drilling unit *Sea Gem*, which had made the first commercial gas discovery in the North Sea, collapsed and sank with the loss of 13 lives. In 1980, the semi-submersible drilling unit *Alexander L. Kielland* broke up in storm weather and capsized with the loss of 123 lives. In 1982, the semi-submersible drilling unit *Ocean Ranger* foundered in severe weather off Newfoundland with the loss of the entire crew of 84. In 1988, the ignition of leaking gas during maintenance work caused the total loss of the *Piper Alpha* platform in the North Sea, with the loss of 167 lives.



Jack-up Drilling Unit (ENSCO)



Semi-submersible Drilling Unit (Noble)



Drillship (BP)

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Sea Gem (Dukes Wood Oil Museum)

These and other major offshore incidents have had a profound effect on the perception and management of risk in the offshore industry:

- The techniques of jack-up leg design, in particular, the analysis of the interaction between the legs and supporting sea bed soils and of the hydrodynamic loads imposed by waves and currents, have developed considerably, with significantly greater capability in dynamic modelling, structural design and geotechnical prediction.
- Structural design and fatigue analysis of semi-submersible drilling and production units has become more precise, together with the techniques for accurate determination of environmental loading on structures.
- Critical systems, such as ballast control, fire and gas detection, emergency shut-down and process control systems are generally subjected to risk-based design and operability analysis.

The primary risks associated with offshore drilling and production include:

- · loss of watertight integrity and stability of unit
- structural failure of unit
- loss of containment of oil and gas on unit
- station-keeping failure (mooring or DP)
- loss of well integrity (blowout)

RISK ASSESSMENT AND INTEGRITY MANAGEMENT

The UK offshore industry took the lead in moving from prescriptive 'box ticking' application of rules and regulations towards a system whereby it can be demonstrated that asset integrity has been determined from risk assessment; that procedures and processes are established to maintain asset integrity, compliance with applicable laws, codes and standards; and that systems are established to monitor and control operational risks.

Regulatory agencies such as the UK Health and Safety Executive (HSE) and the National Offshore Petroleum Safety Authority (NOPSA) in Australia, classification societies such as Lloyd's Register, Det Norske Veritas and the American Bureau of Shipping, and standards bodies such as the American Petroleum Institute (API) and NORSOK (developed by the Norwegian petroleum industry) have progressively adopted risk-based assessment of the design and operation of offshore units, equipment and systems.

Life-cycle integrity management of offshore units involves activities undertaken at each stage of the unit's life cycle, from design, through construction, commissioning, operation and decommissioning, to ensure that risk is identified and analysed, and that processes and procedures are established for operation, inspection, repair and maintenance of the unit. Life-cycle integrity management integrates the design, functionality, personnel competency, operation, maintenance and repair of the unit and ensures compliance with codes, standards and legislation. Design appraisal of offshore units can be based on an evaluation of performance standards for the unit, based on risk assessment of structure and safety-critical systems. Inspections and testing during construction and commissioning ensure compliance with specification and provide a baseline for risk and reliability-driven inspection and maintenance systems during the operational phase, which are integral to optimised life-cycle integrity management. The drive to improve reliability and minimise downtime, thereby reducing operating costs, has led to the implementation of reliabilitycentred maintenance (RCM), linked to risk-based inspection (RBI) schedules. RCM is a process to establish the safe minimum levels of maintenance, based on analysis of failure mode, effect and criticality (FMECA) of structure, systems and equipment. The focus of RCM is to preserve the integrity and functionality of the unit and its systems by developing maintenance schedules that provide an acceptable level of operability within the bounds of an acceptable level of risk. RBI assigns inspection priorities and inspection intervals on the basis of risk analysis, considering the probability and consequences of failure, rather than on a simple time-based schedule that gives equal priority to all, regardless of criticality. Both RBI and RCM follow the principle of ALARP (as low as reasonably practicable) when focusing on risks associated with critical systems to determine priorities for inspection and maintenance. RBI and RCM schemes depend to a great extent on the quality of inspection and maintenance activities, the competence of personnel and adequacy of the information database (structural details, equipment inventory, inspection records, performance data, etc.) that will underpin the system. Additionally, qualitative risk assessment, reliability analysis and FMECA data all contribute to the risk/reliability model that will determine the balance between risk of downtime and inspection effort (and cost). Therefore, the primary elements of a risk-based integrity management scheme are:

- a comprehensive design, construction portfolio
- failure mode analysis (FMECA), reliability analysis, criticality analysis, HAZOP, etc
- ranking of safety-critical equipment and systems
- risk-weighted inspection and maintenance scheme
- comprehensive fault identification, recording and analysis system
- competency and training of operating personnel

Progressive feedback from actual inspection and maintenance activity will refine the risk/reliability model, enabling continuous optimisation of the scheme.

MANAGEMENT OF WELL INTEGRITY AND CONTROL OF BLOWOUT RISK

Well integrity management and well control are prime examples of the application of risk analysis to critical aspects of design and application. Risk analysis is being progressively used in the offshore industry during the planning of wells and the identification of potential hazards. An important part of the analysis is to determine the equipment and procedures necessary to manage both expected and unexpected wellbore conditions and prevent uncontrolled release of wellbore fluids.

In the early days of oilfield operations, there was no way to control the well if the underground pressures encountered in the wellbore during drilling were to suddenly exceed the hydrostatic head of the drilling mud. When the oil or gas reservoir was encountered, wells were just allowed to 'blowout' until the pressure was reduced sufficiently to allow a valve to be fitted to the wellhead.

Well control is the means whereby drilling and production operations can safely proceed without uncontrolled flow of formation fluids from the wellbore (blowout). Primary well control is achieved by the use of drilling fluid (mud) density to provide sufficient hydrostatic pressure to prevent the influx of formation fluids into the wellbore. Drilling mud is pumped down the drill pipe to the drill bit, where it is ejected via nozzles that assist the cutting action of the bit. The returning mud flow up the annulus carries the rock fragments cut by the drill bit (cuttings). These are removed at the surface and the drilling mud is recirculated down the well. The density of the drilling mud has to be such that the hydrostatic head at the bottom of the well balances or slightly exceeds the pore pressure of the formation. The circulating pressure is generally higher than the hydrostatic head, due to dynamic effects and weight of the cuttings. The circulating pressure and flow rate are calculated to optimise bit hydraulics and cuttings transport. The pore pressure is the pressure of fluids that occupy the interstitial spaces between the particles of the rock. As the drill bit penetrates the rock, changes in pore pressure may occur as the bit penetrates a different formation - for example, from a shale to a sandstone. If the density of the drilling mud is too great, the rate of penetration (ROP) will be slowed down and there will be a risk of causing formation damage by mud infiltration into the formation or even exceeding the formation fracture pressure. This can lead to loss of drilling mud into the formation (lost circulation). If the density of the drilling mud is less than the pore pressure, ROP will be high, but there will be a risk of influx of formation fluid to the wellbore (known as a 'kick'). Sometimes, where the lithology and formation tops are known, drilling may proceed with a drilling mud density of less than the formation pore pressure. This 'underbalanced drilling' allows for high ROP and 'drilling for kicks', where an influx indicates that a formation target has been reached.

Primary well control procedures require the close monitoring of drilling fluid circulation volume, ROP and the composition of the fluid and solid returns that are circulated up the wellbore, particularly if drilling underbalanced. Any gain in circulating volume indicates an influx from the wellbore. There may also be an increase in the level of gas in the drilling mud, which can be detected by mud-logging instruments. At intervals, drilling is suspended and checks made for flow in the annulus and, periodically, the mud is circulated 'bottoms up' to check for entrained wellbore fluids.

BLOWOUTS

Blowouts are caused by a loss of hydrostatic balance in the well, due to an influx of formation fluid (oil, gas, water) or the loss of drilling mud into a lost circulation zone (thief zone) causing such a reduction in hydrostatic head that fluids are able to enter from another zone. If the drilling mud density is close to the pore pressure, a kick can occur when circulation stops, e.g. to connect more drill pipe or to check for flow. A kick can lead very quickly to a blowout, particularly if there is a high concentration of gas in the influx. Gas expands very rapidly as it travels up the annulus and displaces the drilling mud. The resultant loss of hydrostatic head allows more gas to enter the annulus and, if unchecked, a blowout occurs.

Blowouts can be caused during tripping operations to change the drill bit or bottom hole assembly. If the bit is withdrawn from the open hole section too quickly, there is a suction effect (swabbing) that causes formation fluid to be drawn into the wellbore. Because the well is not being circulated at that time, the kick will go undetected until there is a flow of drilling mud at the surface.

Well integrity management and well control are prime examples of the application of risk analysis to critical aspects of design and application. Risk analysis is being progressively used in the offshore industry during the planning of wells and the identification of potential hazards. An important part of the analysis is to determine the equipment and procedures necessary to manage both expected and unexpected wellbore conditions and prevent uncontrolled release of wellbore fluids.



Spindletop, Beaumont Texas 1901 (John Trost)

In deep water, a blowout could result from the loss of drilling mud in the riser; for example, to avoid collapse of the riser due to mud losses to a thief zone in the well, most deepwater risers have an automatic fill-up valve that allows seawater to flow into the riser. The density of the seawater will generally be lower than that of the drilling mud, so a significant loss of hydrostatic head will occur in the well.

A blowout may occur when the drilling mud is being displaced from the well and riser during abandonment operations, if there is an inadequate seal between the cement and the casing or liner, or a failure of downhole hangers or plugs.

An underground blowout can occur when fluid from a high-pressure zone flows uncontrolled into a lower-pressure zone, usually higher in the wellbore. Casing programmes are designed to eliminate this risk by isolating different formations from each other.

The general method of dealing with a kick is to shut the well in by closing the blowout preventer (BOP) and circulating the kick to the surface by pumping drilling mud into the bit at a controlled rate and pressure, while passing the return flow through a choke, which can exert back pressure to prevent further influx. This procedure can be complicated in deep water, due to friction and hydrostatic effects in the long, small diameter choke line between the subsea choke valve on the BOP and the choke manifold on the drilling unit.

The first ram-type BOP was introduced in 1922. This mechanism allowed the manual closing of a well and quickly became a standard piece of industry equipment. It was installed on the wellhead, and the rams could be closed to seal off the well, allowing full control of the pressure during drilling and production. The original design could withstand pressures of up to 3,000 psi (pounds per square inch), an industry record at that time.

Modern variants of the ram-type BOP remain the industry standard today; many BOPs on modern drilling units are rated at up to 15,000 psi and are deployed in water depths of 3,000 metres (10,000 feet). There are three types of ram BOP in common use:

- pipe rams
- blind/shear rams
- variable bore rams

Pipe rams are designed to close and seal against the drill pipe and have hard nitrile inserts shaped to the profile of the pipe diameter (typically 5 inches). Blind/shear rams are designed to shear drill pipe, tubing or casing, depending on the ram inserts selected, and then close tightly to provide a pressure-tight barrier or, if no pipe is in the BOP, to close and engage to provide the pressure-tight barrier. Variable bore rams have an 'iris'-type closure (like a camera lens), designed to close and seal against different diameters of drill pipe.

A typical subsea BOP may contain a lower double pipe ram, with inserts sized for the working drill string (typically 5 inch diameter) and an upper double with blind/shear ram and either a 3-inch pipe ram or a variable bore ram. When closing the BOP, it is essential that the drill pipe is 'spaced out' in such a way that the shoulder of the tool joint (the screwed connection between joints of drill pipe, which has a

larger outside diameter than the main body of the pipe) is just above the uppermost pipe ram for the pipe diameter. In that way, the drill string can 'hang' on the upper pipe ram and the lower pipe rams are then able to close and seal against the body of the pipe. The dimensions of the BOP stack also ensure that, in this configuration, the shear rams will be able to close on pipe and not on a tool joint, which they may not cut cleanly.

With the pipe rams closed, the well can then be circulated via the drill string and the choke valve on the BOP stack below the lower pipe ram.



BOP stack (Cameron)

Most deepwater BOPs are rated at 15,000 psi and have a bore of 18¾ inches. The BOP is connected to the drilling unit by a marine drilling riser. The riser, which is tensioned on the drilling unit, conducts the drilling fluid back to the surface, where it is conditioned prior to being pumped back down the drill pipe to the drill bit. The riser is an important component of the well integrity system, particularly in deep water, as the hydrostatic head of fluid in the riser is part of the primary well control system. When the well is shut in at the BOP, this hydrostatic head disappears and account must be taken of that in the well integrity analysis. At the top of the riser, there is a telescopic joint, which absorbs the vertical motions of the drilling unit. There is also a diverter that can be closed to enable discharge of fluid overboard in the event of a shallow gas kick. Whilst the diverter is normally open during drilling operations, increasing use is being made of 'managed pressure drilling', where the diverter is replaced by a rotating control device (RCD) to enable the entire circulatory system, including the riser, to be closed and pressurised. Managed pressure drilling allows precise control of the wellbore pressure profile and has the potential to allow faster corrective action to deal with pressure variations and avoid formation fluid influx while optimising well hydraulics, bit performance and ROP.

Early subsea BOPs were controlled remotely from the surface by pumping hydraulic fluid directly from a control panel on the drill floor to the individual activators on the BOP. As water depths increased, this method became increasingly impractical, due primarily to the time delay between activating a function at the surface and its execution on the BOP, also due to pressure losses over the length of the control hose and the reduction in pressure differential between the control system and the sea at the depth of the BOP.

Deepwater BOPs are controlled by a multiplex system. Commands are sent electronically to control pods on the Lower Marine Riser Package (LMRP), which use solenoid-activated pilot valves to direct hydraulic fluid to the main actuators. Electrical and hydraulic power is transmitted from the surface via umbilicals and stored at the BOP in batteries and accumulators. Each control pod is capable of activating all the functions on the BOP, so there is complete redundancy and the control software carries out continuous tracking and error checking of the status of the control pods and BOP functions. In the event that the umbilical is disconnected, an acoustic backup system can activate the primary functions on the BOP. Remotely Operated Vehicles (ROVs) intervention can also be applied to some primary BOP functions.

The illustration of a deepwater BOP stack shows the 'blue' and 'yellow' control pods on the LMRP. The LMRP also contains a flexjoint to allow for angular deflection of the riser and an annular BOP, which will typically be rated at 5,000 psi. The lower section contains the wellhead connector, BOP rams and accumulators for storage of the hydraulic control fluid.

FAILURE MODES OF BOPS

BOP stacks have long been regarded as the ultimate defence against blowout, and all drill crews receive training in their use. A subsea BOP is generally tested to its rated pressure while on a test stump on board the drilling unit, usually before being deployed on a well. Once the BOP stack is subsea, testing is usually carried out on a weekly basis or prior to special tasks, such as running casing. Regular testing uses a test plug in the casing hanger or in the casing itself. To avoid casing damage if the test plug leaks, the routine tests are usually limited to about 80% of the rated casing burst pressure.

BOP failures may be due to malfunction or inability to provide full pressure containment. As described above, subsea BOP control systems have several levels of redundancy but are not fail-safe, i.e. the status of the BOP is dependent on a command sent from the surface control panel. The only fail-safe sequence is in the event of an emergency disconnect of the riser and LMRP, where a predetermined sequence is automatically triggered when the emergency disconnect function is activated. The emergency disconnect function will close shear rams, subsea choke and kill valves, and release the riser connector but will be dependent on correct space-out of the drill string to ensure that the shear ram does not attempt to close on a tool joint.

BOP control system failure may occur as a result of a loss of electrical power, flat batteries, software malfunction, loss of hydraulic accumulator pressure, leakage of hydraulic fluid from control pods or pilot valve failure.

Failure of a subsea BOP to contain pressure from the wellbore may be due to a number of factors. First and foremost, the drill pipe should be correctly spaced out and stationary when the pipe rams are closed. The annular preventer will close on various diameters of pipe, including open hole, but is generally rated at 5,000 psi. Whilst the annular will permit the movement of pipe (stripping) in the event that the drill string was off bottom at the time of the kick, the pipe rams will not allow the passage of a tool joint. Stripping of pipe through a pipe ram is usually accomplished by ram-to-ram or ram-to-annular procedure, but the full closing pressure is not applied to the pipe ram when pipe is moving. A severe kick can impose a force to eject the drill pipe from the well, or it may be attempted to close pipe rams without the drill string being correctly hung off. Either way, if the pipe rams are closed with full system pressure on moving pipe, the nitrile seal inserts may be damaged or ripped out, thereby preventing a pressure tight seal. Ram BOPs usually have hydraulically activated wedgelocks to keep them closed. If, for any reason, the wedgelocks fail to close and the hydraulic pressure on the rams bleeds down, the rams will not continue to seal.

The ultimate defence is to close the shear rams, cutting the drill pipe and allowing it to slump. If, however, there is a tool joint in the shear ram, it may not effect a clean cut and subsequent seal. If the kick was sufficiently violent, there may be sand, rocks and other debris inside the BOP, or even a dislodged casing hanger, all of which could prevent the shear rams from closing effectively.

CONCLUSION

The progression of the offshore industry into deeper, remote, hostile and environmentally sensitive areas requires a commensurate understanding, assessment and management of the associated risks. Risk-based asset integrity management schemes and well integrity schemes are progressively replacing adherence to prescriptive rules.

The failure of the *Deepwater Horizon's* BOP sends a stark signal that the offshore oil industry's ultimate defence against the risk of blowout for nearly 90 years is not infallible. A radical reappraisal of the role of BOPs in well control, together with a comprehensive examination of the risks inherent in deepwater offshore drilling, could increase confidence in the integrity management of offshore exploration and production.

