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Drilling Well Control Practices and Equipment Considerations for Deepwater Operations Plans

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Abstract

Everyone recognizes the higher costs and technical challenges associated with drilling in deeper waters. As more information about operating in this frontier becomes known, planning and preparation can improve, reducing costs and risks. This paper will discuss well control issues associated with drilling. It will compare and contrast the requirements of the US MMS (Minerals Management Service), the UK and Australian Safety Case and Verification Schemes, and the Regulations and Guidelines of the NPD (Norwegian Petroleum Directorate). Of particular interest is hazard and risk analysis.

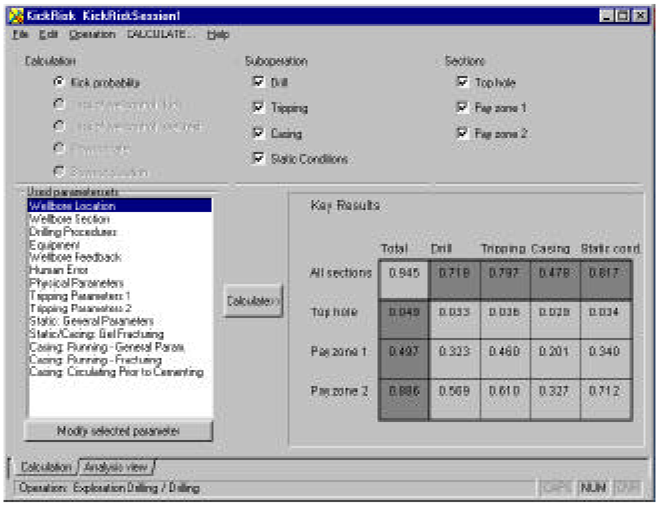
For effective risk analysis, one must first identify the magnitudes and type of events that may occur during a drilling or well control operation. Then, the operational capabilities and limitations of the equipment used to deal with such events can be explored to ensure they are fit for purpose. The net result is that not only can hazards be identified, but also their potential consequences estimated - the very essence of a good hazard analysis. As a result, the operator generates information that will improve the safety of his operation as well as his drilling effectiveness and (as a by-product) meet regulatory mandates.

Introduction

Every drilling program includes risk analyses, completed either explicitly or implicitly. As such, they are conducted for many reasons, including regulatory and prudent business practice. Although more comprehensive analyses undoubtedly reduce risk to a greater level, the expected fruit must be balanced against cost.

For the complete drilling process, assessing risks and consequences associated with well control and blowouts is a complex procedure. **Fig. 1** (courtesy RF Rogaland) indicates some of the complexities of the procedures and the issues that must be addressed (1).

Fig. 1: Example of a comprehensive kick risk analysis



Calculation
● Kick probability

Suboperation
☑ Drill
☑ Tripping
☑ Casing
☑ Static Conditions

Sections
☑ Top hole
☑ Pay zone 1
☑ Pay zone 2

Used parameter sets
Wellbore Location
Wellbore Section
Drilling Procedures
Equipment
Wellbore Feedback
Human Error
Physical Parameters
Tripping Parameters 1
Tripping Parameters 2
Static: General Parameters
Static/Casing: Gel Fracturing
Casing: Running - General Params
Casing: Running - Fracturing
Casing: Circulating Prior to Cementing

Key Results

	Total	Drill	Tripping	Casing	Static cond.
All sections	0.945	0.718	0.797	0.478	0.817
Top hole	0.049	0.033	0.036	0.028	0.034
Pay zone 1	0.497	0.323	0.460	0.201	0.340
Pay zone 2	0.886	0.569	0.610	0.327	0.712

Operation: Exploration Drilling / Drilling

The results shown in the figure are in the form of probabilities of a kick occurring. The figure is included simply to indicate the scope of a complete analysis. No attempt is made in this paper to show how this complete analysis is carried out. It is only possible to quantify the risks and consequences if sufficient analysis is carried out to allow a process to be broken down into simple steps that then allows for a quantitative (or semi quantitative) assessment of failure on the part of an expert.

The process is therefore:

1. Break down overall process into simple steps
2. Assess risk of failure for each step
3. Assess consequence of failure for each step
4. Recombine steps and assessment of risk into an overall analysis
5. Review overall analysis and take action on any steps that produce a high risk/consequence

It is probably more important to identify and take action on those steps which stand out, rather than to reduce the overall risk/consequence level to a preset value. In this way, less importance is placed on the composite number.

Often, regulatory bodies mandate risk analysis and its mitigation. The MMS, UK Australia, and the NPD each have different approaches, each with advantages and drawbacks to both contractors and operators. Varying in the degree of prescription, all can be satisfied with a well thought through risk analysis.

As noted above, such an analysis requires projection of well hydraulics (including kicks), equipment limitations, and other less tangible factors such as human error. This paper will focus on equipment limitations that have not played a significant role in analyses in the past, partly because of lack of information, and partly because the hydraulic head effects on the equipment could be ignored in the shallower water depths previously drilled in.

Discussion

One logical place to start the discussion is with an analysis of regulatory requirements. It is interesting to note that all of the referenced legislation has moved away from prescriptive requirements that specifically state what you must install and how you should operate. Rather, they require the operator and contractor to carefully consider potential difficulties with various normal procedures and reduce the risks associated with them. The disadvantage to the regulated parties is that if a significant accident or event would occur, the default assumption would be that the risk analyses were deficient. Because of the nature of the regulatory language, proving due diligence was adequately completed is more difficult.

MMS. On 1 June 1998, the MMS (Minerals Management Service) NTL (Notice to Lessees) No. 98-8N concerning Deepwater Operations Plans (DWOPs) (2) became effective. This regulation provides a set of guidelines for all deepwater development projects in water depths greater than 1,000 ft and all projects utilizing subsea production technology. The stated purpose for this NTL is to enable operators to provide MMS with information specific to deepwater/subsea equipment issues, demonstrating their project will be developed in an acceptable manner prior to significant expenditures.

A required part of the preliminary data to be filed includes a hazard analysis - "A summary of the process(es) to identify, evaluate, and reduce the likelihood and consequences of uncontrolled hydrocarbon releases or other safety or environmental incidents should be submitted . . ." This requirement appears to mandate a written hazard analysis for operations conducted under the above noted criteria, which one would assume would include drilling operations. However, drilling is not included in the scope of this regulation according to the MMS and is thus only dealt with under previously existing regulations (3). As a result, there are currently no MMS regulatory requirements for risk or hazard analysis regarding drilling in US waters.

UK HSE. The HSE (Health and Safety Executive) utilizes a combination of safety case and verification schemes to ensure the safety of drilling operations in their regulatory area (4). The safety case requires "suitable and sufficient quantitative risk assessment" to be carried out and the identified mitigation undertaken and documented to "reduce risks to the health and safety of persons to the lowest level that is reasonably practicable", alternately called ALARP (As Low As Reasonably Practicable). Other safety case requirements include a statement of performance standards, limits of environmental conditions beyond which the installation cannot be safely operated and a demonstration that "the risks from a major accident are at the lowest level that is reasonably practicable."

NPD. The NPD (Norwegian Petroleum Directorate) regulations require the operator to define acceptance criteria for risk, "taking into account the possibility for as well as the consequences of identified accidental events." (5) Subsequently, "Prior to every operation and when evaluating the risk situation, a separate risk analysis shall be considered carried out." In risk mitigation, priority should be given to reducing the probability of occurrence over reduction of consequence. Finally, a list of analyses that were done shall be documented. Although it recognizes that risk cannot be eliminated, risk shall be reduced ALARP.

Australia. Australia's Submerged Lands Act has many similarities to UK's HSE regulations. They also require safety cases with risk assessments and utilize the ALARP phraseology.

Having reviewed the statutory requirements of various agencies, you can see that risk analysis plays a part in them all. Having referenced this management tool a number of times, let's turn our attention now to its development and use.

Risk Analysis. There are many ways to perform risk analyses, including formalized techniques like HAZOP (Hazard and Operability), Fault Tree, and so forth. There are also many ways to report the findings from these tools. In the great majority of cases, perhaps even in all of them, reporting boils down to understanding the probability a situation will occur, and the consequences of that occurrence.

One good graphical way to illustrate risk analysis is the use of a risk matrix. The matrix plots probability on one axis, and consequence on the other, using qualitative terms. Each company then develops a policy statement on the required action for each combination listed on the matrix. The end result is a way to decide whether risk mitigation is required, and, if so, to what level. **Fig. 2** shows how this matrix might be depicted.

Data development, that is, identifying hazards and assigning probability and consequences, is undoubtedly the most difficult part of the process. This is where access to people with extensive experience and industry wide data add incredible value. Major operators will typically perform hazard analyses and understand the implications of such work. However, in most cases, equipment failures are not considered beyond the configuration of the BOP stack supplied. The requirement for back-up equipment may therefore be recognized, but the actual potential for failure of the primary equipment or the failure path for failure of this equipment is beyond the limits of the analysis.

An Example. Perhaps the best way to illustrate risk analysis is to briefly walk through one for a critical deepwater procedure - emergency disconnects.

Floating drilling operations have identified the need to quickly disconnect the rig from the well. With DP (Dynamically Positioned) rigs, the probability that this will be activated is higher than a moored rig. Thus, the discussion of the EDS (Emergency Disconnect Sequence) in this paper is limited to this operation. With these rigs, the EDS is designed for three circumstances, a drive off, a drift off, and in preparation for rough weather. In any of these emergency situations, the primary objective of the EDS is to make the rig safe and secure the well as quickly as possible. The secondary objective is to disconnect in such a manner as to not damage the equipment and allow rapid re-entry in the well. Failure of the EDS is considered to be low risk event. However, if a failure were to occur, the consequences could be extremely high, especially if the resultant blowout continued for any length of time. A detailed look at such a system is therefore very appropriate.

EDS Background. EDSs have been defined on many floating drilling rigs. When offshore drilling progressed into water beyond 4000 feet, traditional mooring became both more difficult and more costly. As a result, DP (Dynamically Positioned) drilling rigs were designed that depended on multiple thrusters, position sensing devices, and a control computer to keep the rig correctly positioned relative to the wellhead on the sea floor. The rig is connected to the wellhead by the lower stack, the Lower Marine Riser Package (LMRP), and the marine riser. When an emergency disconnect is required, the LMRP and the riser must be disconnected from lower stack to avoid a disaster. See **Fig. 3**.

The control system pods are mounted on the LMRP, which is, in turn, latched to the lower stack. The lower stack contains the wellhead connector, failsafe valves and ram BOPs, including the shearing blind ram, and usually the lower annular. Upon initiating the EDS, the LMRP connector is unlatched, and the marine riser tensioners lift the LMRP and riser away from the lower stack as they stroke out to their maximum length.

Clearly, every EDS is highly dependent upon the design and configuration of the stack. Fourth generation deepwater rigs utilize MUX control systems. MUX systems lend themselves to automating the EDS. A generic automated EDS consists of the following actions:

Wellhead connector - latch
All failsafe valves - closed.
Choke & kill stabs - retract
Shearing blind rams - closed (may or may not shear pipe)
All lower stack functions - block or vent
Lower stack pod stingers - retract
LMRP connector - unlatch
Riser recoil - activate

The Risk Analysis. Let us now work through a risk analysis of the EDS. This process will be illustrated systematically, though not rigorously. Topics that should be considered in this risk analysis are briefly mentioned for each step. Then, two of these topics are covered in some depth after the initial, cursory description.

As an ancillary thought, it is interesting to note the priorities of the party conducting the analysis. Of course all are concerned about the health and safety of the people on their rig. Operators are additionally concerned about their investment in the well and their costs to complete a well. As the holder of the operating permit from the regulatory body, they are furthermore responsible for operating liability. Contractors are more concerned about their capital equipment - the riser and BOP.

The first step is to ask the question on each event - what might happen that would cause the EDS system to fail to meet its objective? Let's work through each step and comment on equipment considerations as appropriate.

Latch the Wellhead Connector. As the wellhead connector is already latched, with latching pressure normally maintained during drilling operations, activating this function should not result in anything changing.

Move the Failsafe Valves to the Closed Position. This is a topic that has been spoken about in a number of industry gatherings, including most recently the 1998 IADC "Deep Water Conference". The presentations brought attention to what people expect of failsafe valves, comparing it to what can be accomplished in deepwater operations. The hydrostatic head of the seawater column differently affects each of the common designs. Details are given elsewhere (6). However, to summarize, be cautious in assuming with a high degree of confidence that your failsafe valves will close and seal. The probability of failure, particularly in water over 4000', covers the full range between low and high, depending on the valve, actuator, and circuit design.

Retract the Choke and Kill Stabs. - no known/anticipated equipment failure factors.

Close the Shearing Blind Rams. After rams are closed, they are locked into position so that, if close pressure is lost, the ram blocks do not move, maintaining the seal. As this feature is particularly important in EDS, it is becoming more common to pressure test rams on the stump with locks engaged and all operating pressure released. On the other hand, it is unusual to test in this same manner on the well. Considering the consequence of locking system failure, it seems prudent to pressure test at least the shearing blind rams (and, not germane to the EDS sequence but also important, the hangoff rams) on the wellhead after releasing the closing pressure.

Drilling in deeper waters increases the need to understand a variety of ram operating parameters. Among those of particular interest is the effect of the hydrostatic head on the forces acting on the ram piston and on some locking system designs. These effects will be covered in more detail below.

Block or Vent All Lower Stack Functions. - no known/ anticipated equipment failure factors.

Retract Lower Stack Pod Stringers. - no known/anticipated equipment failure factors.

Unlatch the LMRP Connector. Every connector has maintenance that must be performed faithfully to ensure highest reliability. If this maintenance is done according to the manufacturer's recommended schedule using OEM (Original Equipment Manufacturer) parts and lubricants, the probability of failure is remote. However, a common problem that makes maintenance difficult is the design of the stack handling system. If maintenance of the LMRP connector was not considered in the design and construction of the rig and the system handles the lower stack and LMRP as a unit, the LMRP connector may not be able to be unlatched and lifted enough to allow proper maintenance. This means the only way to perform maintenance is when the stack is over the rotary table, requiring shutting down the drilling operation. Since many contracts between the operator and the rig would define this as downtime, for which the rig may not be able to charge their dayrate, one might guess that the actual maintenance frequency is less than is recommended. In the final analysis, if your LMRP connector fails to unlatch, none of the other steps in the sequence have value.

Activate the Riser Recoil System. Early rigs did not have riser recoil systems, which resulted in rig damage. The potential for damage was greater in instances where the rig began operating in envelopes outside what they had previously considered. Although this issue has many factors, there seems to be a good understanding of how to calculate and set these systems.

Overall EDS Issues.

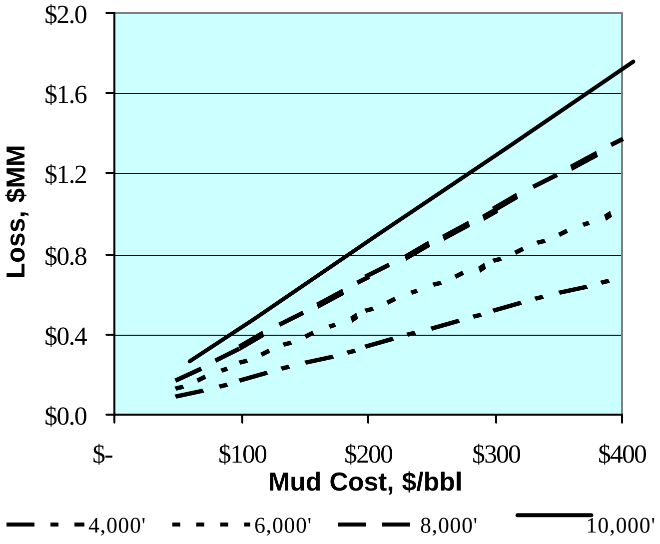
Time to Disconnect. The circumstances that require activation of the EDS often progress very quickly. Common industry practice is to target for completion of the EDS in 30 to 40 seconds. Sequences that take longer than this cause experienced personnel in DP operations concern and result in exercises to reduce the time requirements. Of note here is the relationship between this requirement and the requirements of the world's leading industry standards organization, API (American Petroleum Institute). The response times mandated in API Specification 16D (7) "Specification for Control Systems for Drilling Well Control Equipment" for electro-hydraulic and MUX control systems are the same as for hydraulic systems, namely, 30 seconds for ram operation and 45 for annular. The API RP (Recommended Practice) that parallels the 16D design standard is RP 16E (8) "Recommended Practice for Design of Control Systems for Drilling Well Control Equipment". This RP recommends the same required response times. It is obvious that simply meeting these API documents *will not* allow meeting the 30 second EDS guideline that is now in common use.

With hydraulic systems, programming the EDS required consideration of another variable - the time for the signal to reach the BOP. As a result, the EDS on these systems included more function overlap. For the MUX system designs that rely on transmission of electrical signals, this signal travel time now approaches zero and is thus not a factor. One example of the time relationships between steps in a MUX EDS is illustrated in **Fig. 4**.

On one early DP rig, an "early warning" off position indicator light was installed to allow some activity before pushing the EDS start button. This represented good engineering judgment considering the knowledge available at the time. However, the rig experience in operation demonstrated that this early warning feature provided at most a few seconds of warning. As a result, this provided so little value that it was disconnected.

Mud Volumes Lost as a Result of Executing the Sequence. Every time the EDS is activated, the standard result is lifting the LMRP off the lower stack, resulting in an open hole under the column of drilling mud in the riser bore. In the time between the EDS activation and re-entering the well, the entire column of mud can be lost to the sea. **Fig. 5** represents a non-trivial loss to the operator.

Fig. 5 Mud Losses for EDS



Although mud losses are solely an economic consideration, inclusion of any process that eliminates such mud loss will have a significant impact on the overall operation of the EDS. Accordingly this discussion of mud losses is an example of a potential change to an operating procedure. Proper management of this change is essential.

Mud losses can be eliminated if the annulus in the LMRP above the sheared pipe can be sealed before it is disconnected. The obvious first reaction is to accomplish this by putting another step in the EDS to close the upper annular before disconnecting. However, this should not be inserted without a thorough review of operating parameters and the effects on both individual equipment and the full rig system. This will be covered in more detail below.

Let's now scrutinize several aspects of two of the above points. Although the detail in this section is more substantial, in the interest of brevity for the paper, it still does not reflect the type of comprehensive, systematic approach for typical risk analysis. Rather, it attempts to focus on equipment issues that may not have been previously considered or well understood.

Shear Ram Closing, Shearing, and Sealing. As water depth increases, the effects of hydrostatic pressure on ram BOPs becomes more pronounced. This is true of both pipe and shear rams. Since both wellbore and control fluid have different densities, the differential pressure between the two systems increases with depth. The net effect of the forces generated by this differential pressure is an opening force on the rams. Increased closing control system pressure is required to overcome this opening force.

To calculate the increased closing control pressure required, consider **Fig. 6**. This schematic shows the forces developed by each component of the system. A sample calculation is as follows:

Equipment: 18 ¾" 15K Generic Ram BOP
Operators:
Operator close piston area: 250 in^2
Ram shaft diameter: 35 in^2

Hydrostatic Calculations:
Fluid densities
Control fluid: 0.445 psi/ft
Mud:
14 ppg = 14 ppg × 0.0519 psi/ft/ppg = 0.728 psi/ft
Hydrostatic pressure at 7,500 foot water depth
Control fluid:
0.445 psi/ft × 7,500 ft = 3,338 psi
Mud
0.728 psi/ft × 7,500 ft = 5,460 psi

Pressure differential:
5,460 psi - 3,338 psi = 2,122 psi

Opening force against the ram shaft at 2,122 psi:
2,122 psi × 35 in^2 = 74,270 lb_f

Operating pressure increase required to overcome opening force:
74,270 lb_f ÷ 250 in^2 = 297 psi

In this specific example, in order to exert the same force on the shear blades at 7,500 feet subsea, control system operating pressure must be 300 psi higher. Of course, to do so, the system has to be able to deliver such pressure, and the operator must be able to contain this added pressure.

Ability to Shear Pipe. Because the circumstances that cause the need for the EDS to occur rapidly, drilling personnel have to be trained to immediately hit the EDS button. Until recently, the standard EDS was ineffectual when running casing as standard shear rams would not shear casing. As a result, casing shear rams were developed and are generally on the current fourth generation rigs. On DP rigs without casing shear rams, special precautions should be engaged when preparing to run casing.

There is another situation that is of interest concerning shearing drill pipe - the inability of standard shear rams to shear drill pipe at the tool joint.

Tool joints are about 30 to 35 inches long, and a typical drill pipe joint is 33 feet. This gives a probability of one in 11 that the EDS will be activated on the tool joint, assuming the driller immediately hits the button without regard to pipe position. Although this is a high probability for risk analysis, analyzing tool joint position takes some amount of time. This must be added to the automated EDS completion for an accurate picture of total time required.

Another issue has to do with the ability to shear today's new, high strength drill pipe. Obviously, the most definitive way to know whether your shear ram can shear your planned drill pipe is to test it. The biggest problem with extrapolating the results of other tests is the lack of all the required mechanical data on the tested pipe.

Shear Ram Sealing. The relatively new casing shear rams were developed to cover that part of the drilling program where casing is being run. There is at least one known instance when activating an EDS was required while running casing. However, most casing shear rams will *not* seal.

A solution now being implemented by one contractor is to install a control loop on the lower stack that operates the blind shear rams automatically five minutes after completing the EDS. This requires a timer and a self-contained control circuit on the lower stack to supply the required hydraulic energy for closing.

Locking System Design. Hydrostatic head contributes to the operation of some locking systems. Particularly with flow dependent designs, the wellbore pressure effects described above have caused sequencing problems, resulting in lock damage or, more critical for EDS, inoperative locks.

Mud Losses. There are several key issues to resolve in considering the ability to reduce mud losses in an EDS:

Situations when this step would be useful,
Capability of the annular to hold pressure from the top,
Impact on EDS timing,
Impact on EDS hydraulic volume requirements, and
Effect of additional weight in riser during the EDS.

As noted earlier, the major driving force behind this question is simply the cost of the mud lost when the EDS is activated. Because the mud in the riser is heavier than the surrounding seawater, it quickly flows out the open bottom of the riser, being replaced by air from the top, until the pressure at the bottom of the riser (mud plus air) equals the seawater pressure. From that point, the mud flows out more slowly because of the difference in density compared to water. Thus, the liquid level in the riser increases until full. The speed of this fill-up is difficult to calculate, depending on the differential density, coefficient of friction between the mud and the riser, and the mud fluid properties (viscosity, adhesion, etc.). The point of this entire section is how fast you program the annular to close in relation to the rest of the

EDS, realizing that minimizing mud losses is only a secondary objective of the EDS.

In What Situations Might Mud Losses be Minimized? Stack configuration is critical to this analysis. If it were necessary to bring the LMRP to the surface, a circulation path would have to be established to allow the mud to be returned to the pit for subsequent re-use, saving the cost of a new riser volume of mud. Example situations that would cause LMRP retrieval are equipment damage during the EDS and necessity to move away from the well for an approaching storm.

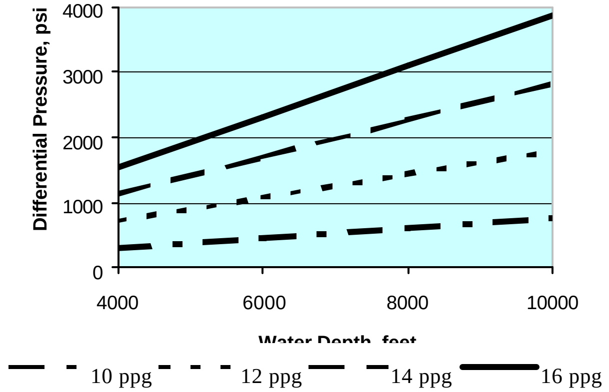
The most likely path for circulating mud out of the riser would be to use the mud boost line. This line ties into the LMRP directly above the flex joint, and was designed to increase the mud velocity in the riser to better carry drill cuttings. Most rigs using 21" riser have this capability.

Another possibility is to use annular bleed, or sweep valves. Depending on whether one or two annulars are located on the LMRP and the location of the sweep valve(s), this might be a way to circulate the mud out of the riser for reclamation. The most common configuration that allows this is with both annulars on the LMRP.

The next consideration is the capability of your annular to hold pressure from the top. **Fig. 7** shows the pressure that would be imposed on the top of an annular preventer for a range of water depths and mud weights within the riser.

Fig. 7. Effective Mud Pressure at Depth

Compensated for Water Displaced



How Much Can an Annular Hold from the Top? The easiest way to begin this discussion is to state that annulars are not designed to hold pressure from the top. Because annulars must seal in a broader range of circumstances, including on open hole, their designs must include a greater amount of rubber. This is simultaneously the reason for their lower pressure ratings. To hold this greater rubber volume in place, metal support fingers are used. The risk in closing the annular in this manner is that the rubber may go "inside out". However, simply because annulars are not designed to hold pressure from the top does not mean that they will not do so.

Cameron testing has caused them to state their annulars will hold a mud column in when closed on 5" pipe by new packers up to about 1/3 of the rated working pressure. Testing was limited in scope, and was done only on new packers. Thus, predicting capabilities on used packers and/or on drill pipe sizes other than 5" would drastically reduce your level of confidence in their capabilities.

Hydril also has conducted limited testing of their 18 ¾" 10K GX annular, and concluded their capabilities as 1000 psi less than the closing pressure applied. As the annular regulator would normally be set at only 1500 psi, closing a GX annular to reduce mud losses would be most effective if the regulator pressure were increased before or during the annular closing in the EDS.

All the manufacturers stressed that testing annulars for holding pressure from the top was extremely limited. Thus, any plans to utilize this method to limit mud losses must involve communication with the manufacturer to improve the understanding of the parameters in your program. Considering the interest in this topic, it would seem reasonable to engage testing programs to increase our confidence in this equipment capability.

Of course, the effect of closing an annular while flowing through it from the top is not well known. One might expect that this flowing condition would increase the likelihood of the rubber going "inside out", since, once it is closed, the element has additional mechanical strength from the contact of the element components. Testing for this would be extremely difficult, but should be considered.

How Would Closing an Annular Affect EDS Timing? As alluded to earlier, in order to eliminate mud losses, the annular would have to be closed before the LMRP connector is unlatched. The combination of the time required to close an annular and the target EDS completion target of 30 to 40 seconds makes this ill advised. The more logical choice would be to initiate the annular close function after lifting the LMRP off the lower stack. Although some mud would be lost, it would certainly be less than the full volume of the riser.

To think this one through, consider how the control systems work. Subsea control systems involve five major components: a pump to supply pressure to the control system, surface accumulators to provide capacity as functions are activated, subsea accumulators for an immediate supply of control fluid to the stack, and transportation systems between the two accumulator systems, and between the subsea accumulator and the stack. Because the subsea accumulator system was designed to "instantaneously" deliver control fluid to the stack, the time effects of the latter transportation system can be ignored. However, in spite of the fact there can be a two-inch nominal ID pipe sending control fluid to the stack from the rig, there is a measurable time lag to deliver fluid from the rig to the stack.

How Would Closing an Annular Affect EDS Volumetric Requirements? An understanding of this time lag is important in the dynamic analysis of the EDS.

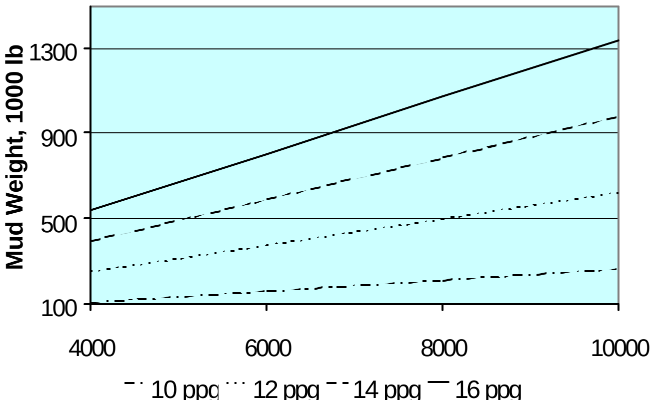
Activating each of the EDS steps requires a known volume of control fluid. If the annular close function is added to the EDS, the volume stored in the subsea accumulator bottles may be insufficient without recharging from the surface system. This adds time for the annular to close. Adding additional volume to the subsea accumulators would reduce or eliminate this time lag, further reducing mud loss.

What are the Effects of Maintaining More Weight in the Riser String? From a static analysis, retaining the mud in the riser after an EDS needs to consider several additional issues.

Directly upon unlatching the LMRP connector in an EDS, a series of complex dynamic actions are set in motion. The most obvious is that the riser tensioners, which are normally set to overpull 50,000 lb$_f$ or so, begin to retract. To this, one needs to add the weight from the lost mud, see **Fig. 8**.

Fig. 8. Effective Mud Weight in Riser

Compensated for Water Displaced



As soon as the LMRP begins to clear the mandrel, mud begins to pour out the bottom of the annular (depending on the annular close situation being discussed). The mud flows out more quickly as the open area increases. At the same time, the riser recoil system begins to reduce the pull provided by the tensioners. This recoil system has to be properly set, considering tensioners in service, weight of mud in the riser, and overpull setting. If the recoil system is not correctly set, a catastrophic collision between the telescopic joint and the diverter would occur. Because of the speed that the tensioners react, whether or not the annular is closed is not expected to impact the riser recoil settings.

If the annular close was included in the EDS, the possibility of riser collapse would be reduced. The initial mud lost without this function can be easily calculated.

Let's return to the thought process engaged earlier - mud is flowing out of the riser as the LMRP lifts off the mandrel. Mud continues to drain out of the riser, being replaced with air from the top, until the pressure at the bottom of the riser equalizes inside and outside the riser. The level of the mud/air interface can be shown below:

Pressures at depth:

Water gradient: 0.445 psi/ft

Water pressure:

0.445 psi/ft × 7,500 ft = 3,338 psi

Mud weight:

14 ppg = 14 ppg × 0.0519 psi/ft/ppg = 0.728 psi/ft

Ignoring the pressure of air in the riser, initial equilibrium mud height:

3.338 psi ÷ 0.728 psi/ft = 4,585 ft. of mud

Crushing pressure outside riser at the mud/air interface:

7,500 ft - 4,585 ft = 2,915 ft of water

2,915 ft of water × 0.445 psi/ft = 1,300 psi

Of course, if a riser fill up valve was installed in the riser in the top 2,915 ft of riser, seawater would fill the voided riser, eliminating the prospect of collapse. However, if such were not installed, or did not work, and the collapse resistance of the riser is lower than 1,300 psi, you would have a problem. With the riser now being installed on newer rigs, this is not expected to be a problem, even at water depths now at the upper fringe of design capacities.

So what is the weight of the mud lost from the time the LMRP connector is unlatched until the first equilibrium (assuming the fill-up valve has not operated):

Riser Volume

Riser ID: 19.75 in

Riser volume

(19.75 in ÷ 12 in/ft)^2 × π ÷ 4 × 1 ft = 2.13 ft^3/ft

2.13 ft^3/ft × 7.48 gal/ ft^3 = 15.9 gal/ft

Weight initially lost from mud:

2,915 ft of mud × 15.9 gal/ft × (14 ppg – 8.34 ppg)

= 262,332 lb$_m$

Depending on how fast the mud is lost, this can have a substantial impact on the requirements of the riser recoil design.

Another consideration is the impact of the higher weight of the full riser on prospective harmonic motion of the riser. The natural wave motion induces periodic vertical motion of the rig. The reaction of the riser to this motion has many variables, weight, stiffness, amount of energy input into the riser string by the motion, current at different levels, and so on. This makes calculations difficult to do and reduces confidence in such calculations. However, there has been at least one operation of which the authors are aware that indicate this is a potential problem. By the time this paper is presented, additional information on this issue will have been gathered.

Conclusions

1. Formalizing the process of risk analysis has resulted in a number of changes in deepwater operations, e.g., the development and use of casing rams.
2. A better understanding of equipment and systems failure modes throughout the industry will lead to a general improvement of risk analyses. This in turn will lead to fewer critical downtime incidents, lower risk for high consequence events, and generally improved operating results
3. A detailed breakdown of the equipment components and all of the steps involved in operating and maintaining such equipment is an essential element of such an analysis
4. Whereas much of the understanding of the components of an overall risk evaluation approach is in place, further work is required such that a comprehensive review of such issues can be routinely carried out.

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