3.7.6 Uninterruptible power supplies

The UPS supplies sufficient power to operate the control panels for at least two hours after the loss of main power. The UPS does ***NOT*** supply power to the pumps so the system can only make use of the stored hydraulic fluid in the accumulator systems when under battery power.

3.8 CONTROL SYSTEM TYPES

Subsea BOP control systems normally fall into one of two classifications: Conventional or MUX.

3.8.1 Conventional controls

As operational water depths increase, response time become more difficult to meet and, in most cases, a conventional hydraulic control system will not meet the requirements. (This is also known as discreet hydraulic controls.)

A conventional, discrete hydraulic, control system sends the control pressures down 3⁄16–in. ID hoses to position the subsea pod valves in the appropriate positions to feed the power fluid, from the 1-in. center core, to the required control valve(s).

Pressure-biased hydraulic systems, which maintain a minimum pressure within the lines to reduce expansion time, extend the use of hydraulic systems from shallow water through the mid-water range, but the majority of floating drilling vessels today employ a MUX system.

Conventional hydraulic control systems are generally limited to 3,000 ft (900 m) water depth (WD). However, some of these conventional systems have been used in up to 5,000 ft (1,500 m) WD with some success by adding pressure-biased components to the pilot system.

3.8.2 Multiplex (MUX) controls

A multiplex system is one by which multiple analog message signals or digital data streams are combined into one signal over twisted pair, or fiber-optic, cables. These multiple messages contain signals to open or close valves, modify regulator pressures, extend or retract cylinders and to transmit pressures, temperatures and position information etc, back to surface.

A MUX system also makes it easily possible to program emergency disconnect sequences (EDS), which provide single button activation of whatever functions are necessary to release the rig from the well.

There really is no physical limit to the water depth in which a MUX system that can be used, though cost is somewhat of a prohibitive factor for a shallow water operation.

Apart from the speed of operation, the biggest benefit of a multiplex system over a discrete hydraulic control system is the read-back and diagnostic capability provided by the computer systems. Pressures, temperatures, earth leakages, solenoid operating currents, etc. are all able to be displayed on the panels for real-time monitoring and troubleshooting.

Little, if any, such capability is possible from a hydraulic control system.

3.8.3 Emergency Control Systems

Emergency controls include:

- EDS;
- Deadman system;
- Autoshear;

3.8.3.1 EDS

All dynamically positioned (DP) rigs must have a manually activated sequence that disconnects the LMRP from the stack to release the vessel from the well. In most cases the sequence includes shearing the pipe and sealing the well. Some rigs have selectable options for sequences to suit operational requirements.

These systems are known as emergency disconnect sequences (EDS).

These are required in the event of a loss of power, a failure of the DP system or other unforeseen circumstance that requires making the well safe and disconnecting the rig from the well.

A single action fires the sequence. This removes the need for the drill crew to activate a series of functions in the correct order and timing when under the stress of an emergency situation.

The drilling contractor’s procedures should plan for the drill string to be spaced out (moving tool joints away from the shear ram) if there is enough time before activating the sequence.

EDS may be fitted to moored rigs depending on the planned program. This will be agreed between the drilling contractor and the well-operator.

3.8.3.2 Deadman

The deadman system will automatically close sealing shear rams in the event of a simultaneous loss of BOP fluid and power from both control pods. This system is designed to make the well safe if the marine riser (and everything attached to it) is lost, or there is a major fire and/or explosion on the rig.

For this reason it is important that the MUX cables and the drape hoses in the moonpool are ***NOT*** fireproof. If these do not fail in the event of a fire then the deadman system may not operate.

The system must be armed as part of the BOP installation procedure. The deadman system may need to be disarmed during certain operational procedures; such disarming should be policed by a management of change (MOC).

These systems need sufficient hydraulic power in the subsea accumulator to carry out all the required functions and this accumulator must be hydraulically protected so that loss of the primary hydraulic supply does not drain the emergency system.

Some automatic functions need a subsea battery to operate. There should be a system for ensuring that functionality of the system is maintained during operations.

3.8.3.3 Autoshear

This system will shear the pipe and seal the well if the LMRP unlatches and lifts of from the BOP.

The system should be armed when, or immediately after the LMRP is latched to the BOP. This may be done remotely from surface or subsea using the ROV.

Autoshear may need to be disarmed during certain operational procedures; such disarming should be policed by a management of change (MOC).

3.8.3.4 Emergency dedicated accumulator

All subsea BOP stacks must incorporate accumulators to power the emergency functions.

Nitrogen remains the precharge gas of choice, although helium has its benefits, but the former is easier to source worldwide or generate onboard the rig and has fewer leakage and diffusion issues than the latter.

Float type accumulators are generally unsuitable for deepwater/ high pressure combinations. Bladder type bottles are normally only of 15 USG nominal capacity and therefore may require quantities that the available real estate may be unable to accommodate. This leaves the newer depth compensated devices, which rely on the hydrostatic pressure to improve the output or the more common large volume (80 – 250 USG) piston accumulators; however, these devices have their limits and drawbacks as well.

Normal subsea accumulator system pressures are 5,000 psi but 7,500 psi is already in use on some systems in an attempt to reduce the bottle count (stored volume required).

The fluid for the emergency dedicated accumulator comes from the surface supply. The accumulator itself is normally located within the lower stack frame but can be on a separate skid that is landed close by, and connected to, the BOP stack.

There is a requirement of API S53 4th Edition to carry out a drawdown test of this emergency dedicated accumulator by isolating the supply to the accumulator and then discharging the greatest consuming emergency sequence. The remaining pressure must be adequate to secure the well.

Accumulator sizing calculation Methods A, B, and C are defined in API 16D.

Accumulator precharge shall be calculated with the manufacturer specified method (A, B or C), using the control system manufacturer-supplied surface base pressure adjusted for water depth and operating temperature as required.

A non-optimal precharge pressure may be used provided that the accumulator system meets the functional volume requirements.

The calculated precharge pressures along with documentation supporting non-optimal precharge pressures (if used) shall be filed with the well specific data package.

Method A

Method A calculations are based on an ideal gas, isothermal discharge. This calculation method shall not be used for accumulator systems with operating pressures above 5,015 lb/sq in. or that require rapid discharge of most of their fluid. Currently, Method A calculations are recognized within the4 industry, but are not applicable to deepwater subsea operations.

In the past Method A was the only method used for volumetric calculations. As we progressed into ever deeper water it became obvious that these simple calculations were inadequate and Methods B and C which consider temperature and real gas characteristics have been developed.

Method B

Method B calculations are based on a real gas, isothermal discharge. This calculation method shall not be used for accumulator systems that require rapid discharge of most of their fluid.

Method C

Method C calculations are based on a real gas, adiabatic discharge. This calculation method is required for accumulator systems that require rapid discharge of most of their fluid.

Documentation for sequenced method C systems shall include each sequenced step with the following applied:

- Using the maximum minimum operating pressure (MOP) during each step;
- Functional volume requirements (FVR) shall be additive with each additional step;
- Precharge pressure shall be maintained constant throughout each sequenced step.

3.8.4 Secondary control systems

Secondary controls include:

- ROV intervention;
- Acoustic control systems.

When emergency and/or secondary controls are installed, the drilling contractor should ensure that they are fit-for-purpose. They should be adequately maintained and correctly installed so they will fulfill the functions for which they are designed.

The suitability of these systems should be demonstrated to the well-operator to check they are suitable for the planned well operations.

The well-operator should review the suitability of any emergency or secondary control systems as part of their assurance that the well control equipment is suitable for the proposed well and conditions.

Some systems are programmable. The drilling contractor should decide on the sequence and timings for the proposed well. This should be reviewed with the well-operator as part of the well risk assessment and planning process.

3.8.4.1 ROV intervention panels

High flow stabs, receptacles and piping sized to meet API S53 closing times should be used for critical functions to allow any vessel of opportunity to support any stack. Compatibility should be confirmed.

As per API S53 fourth edition, critical functions are riser connector unlatch, each shear Ram, one pipe-ram and all applicable ram locks and these are the minimum functions that must be operable by an ROV.

3.8.4.2 Acoustic controls

Acoustic controls are an optional secondary control system designed to operate designated BOP & LMRP stack functions and may be used when primary system is inoperable.

Deadman and auto-shear systems are now mandated on all subsea BOP stacks. Acoustic control systems are also often installed, though these currently remain legislatively optional in many parts of the world.

3.9 PREVENTIVE MAINTENANCE CONSIDERATIONS

Maintenance for a subsea stack and its components is critical to a safe operation.

API S53, 4th Edition, has transferred the ownership of the maintenance from the OEM to the equipment owner. This is necessary because the OEM writes recommendations to cover the lowest common denominator of users which, in many cases, created unnecessary routines, both in scope and in frequency, for the contractors with professional competent maintenance crews.

The same document has also allowed for reliability data to supersede time as a foundation for the maintenance scheduling which will benefit the industry as the data is acquired.

Maintenance covers everything from the somewhat cursory between- wells inspections through to the total strip down for the full major maintenance routines (previously the 3-5 year inspections).

In the past a common practice was to send the major components to shore to have this work carried out. In today's world of in-depth training courses provided by the OEMs, field-replaceable components and the extensive use of corrosion-resistant alloys (CRA) and other coatings in the critical seal areas, this is no longer necessary. The work can normally be carried out offshore. Of course if any remanufacture (hot work or machining) is necessary then the equipment may need to go to shore.

Also in the past it was considered normal for the Between Wells maintenance time to be dictated by the well program. Moving forward it is more common for the duration to be (rightly) planned to fit the time required to complete the necessary maintenance. It is much less expensive, for all parties, to take an extra day or two to complete the planned maintenance while the BOP stack is on surface than it is to spend a week or two when it turns into corrective maintenance and the stack has to be retrieved.

3.9.1 Certificate of conformance

A Certificate of Conformance (COC) does ***NOT*** expire. It is a simple statement that says a particular piece of equipment was designed to a certain standard(s) by a particular manufacturer on a certain date in a particular place, and, as such does not expire.

API S53, 4th Edition states that this equipment must be inspected and maintained. As long as this is correctly implemented, there is no need to have any further certification for the equipment.

3.10 MANAGED PRESSURE DRILLING CONSIDERATIONS

3.10.1 Managed pressure drilling

While conventional drilling uses the hydrostatic pressure of the drilling mud to manage pressure in the well, managed pressure drilling (MPD) uses a combination of surface pressure, hydrostatic pressure of the mud and annular friction, to balance the exposed formation pressure.

The addition of specialized MPD equipment such as the rotating control device (RCD) and MPD choke in applied backpressure MPD operations, enable the application of surface pressure to achieve the desired annular pressure profile. This may result in the added MPD equipment forming an integral part of the primary barrier envelope if the drilling mud weight is underbalanced to pore pressure. In all cases, MPD equipment may be considered as an operational barrier independent of the secondary barrier envelope. The rig's BOPs and choke and kill lines remain as the core emergency barrier components of the secondary barrier envelope.

For deepwater applications, an example of an applied backpressure MPD process flow diagram is shown in the following figure. The primary flow path of annular fluid is routed back to surface from a point below the rotary table and the RCD through to the shakers.

Consideration must be given to all line sizes, flow and pressure ratings within the system.

3.10.1.1 RCD placement

On floating rigs, installation of the RCD should be at a point that is fixed relative to the Earth; otherwise uncontrolled movement

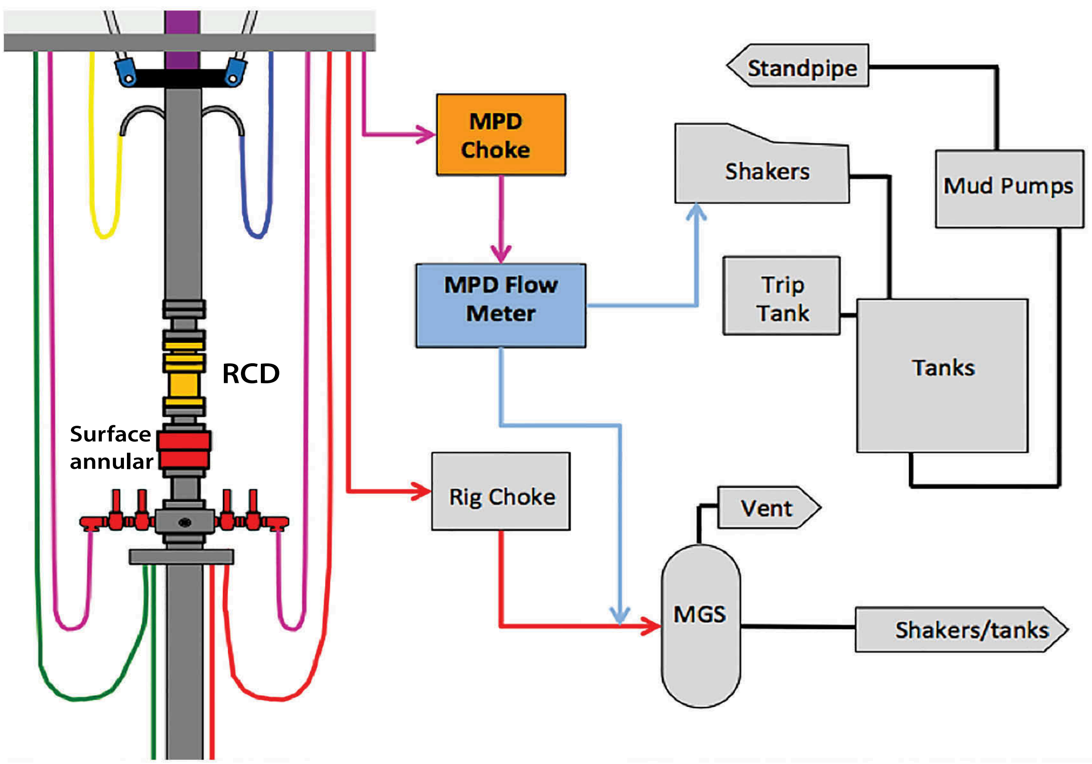

Figure 3.6 — Managed pressure drilling uses a combination of surface pressure, hydrostatic pressure of the mud and annular friction, to balance the exposed formation pressure. The RCD is the orange spool in the riser, below which, in red, is the surface annular preventer. The process shown above is applied back pressure MPD.

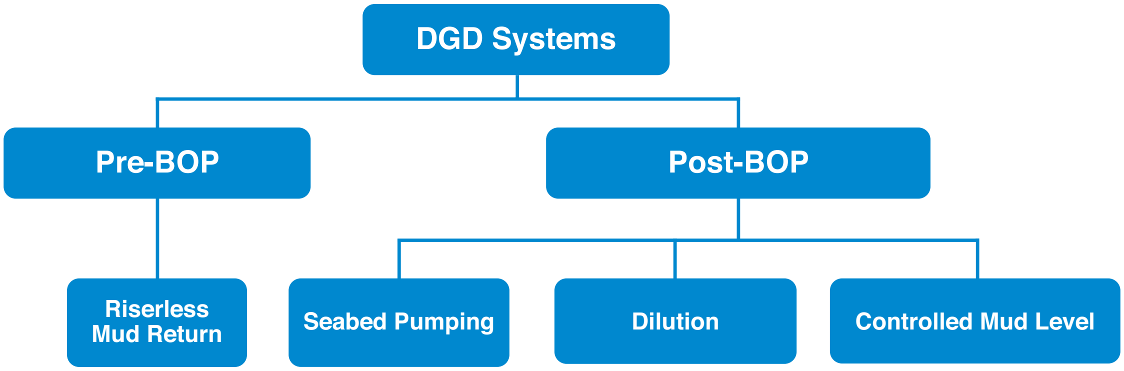

Figure 3.7 — Dual gradient, as defined by IADC, means "two or more pressure gradients within selected well sections to manage the well pressure profile. Several techniques can achieve a DGD system.

of tool joints through the RCD could cause premature sealing element wear and therefore an increased frequency of replacement of the element.

3.10.1.2 Surface annular

The RCD's internal sealing element is a consumable item and will need replacement during drilling. A surface annular preventer is used to facilitate this process, which may be closed during element replacement providing a mechanical barrier to wellbore pressures.

3.10.1.3 Primary flow spool placement

The type of floating rig on which MPD equipment is installed will affect the location of the primary flow spool. Placement is more critical for dynamically positioned rigs, as the length of the flow lines must be adequate to allow rotation of the rig around the riser.

3.10.1.4 MUX, choke and kill lines

Installation of MPD equipment in the riser may impact the routing of the rig's MUX, choke and kill lines. These lines may need to jumper across the MPD equipment if it is installed below the termination joint. Conversely, if the MPD equipment is installed above the termination joint, its location may be pushed deeper and further away from the surface. Longer lines may therefore be required.

3.10.1.5 Riser stress and recoil analysis

Depending on the type of MPD employed on the rig, the riser may experience higher (applied back pressure MPD) or lower (dynamic mud cap) internal pressures than conventional drilling. The riser and recoil analyses mentioned in section 3.5.1.8 and 3.5.1.9 must take into account these new pressure states.

3.10.2 Dual gradient drilling

Dual gradient drilling (DGD) is a subset of MPD. As defined by the IADC, DGD means "two or more pressure gradients within selected well sections to manage the well pressure profile."

Several techniques can achieve a DGD system, each will require specific equipment to be installed with various levels of complexity and rig integration challenges, i.e. subsea pumps, subsea or surface RCD, modified riser joints, surface equipment, control systems.

The IADC MPD selection tool may be used to assist in the selection of the best MPD or DGD technique for a particular need.

3.11 BOP/LMRP HANDLING

There are a large number of methods employed for BOP stack handling ranging from bridge cranes and trolleys to skid beams and transporters. In all cases static and dynamic loading should be considered.

The transporter, spider beams or trolley load ratings must be sufficient for the combined weight of the stack and first riser joint(s) load and needs to take the operational weight, not the initial design weight, of the BOP stack into account. The same applies for the stack and LMRP hang off points.

Under hull guidance may be part of the system and is employed to reduce swing movements of BOP and riser through the moonpool and splash zone.

These systems are not part of the well control equipment and therefore will not be discussed further in this document.

CHAPTER 4

WELL CONTROL PROCEDURES

Committee Members and Contributors

Earl Robinson (Chairman), *Murphy Exploration and Production Co.*

Barry Braniff, *Transocean*

Bill Burch, *Mercury Well Control*

David Foster, *Transocean*

Doug Foster, *SeaTech Offshore*

Innocent Ituah, *Shell*

Charlie Jones, *Noble Drilling Services, Inc.*

Benny Mason, *RigQA International*

John Rogers Smith, *Louisiana State University*

Paul Sonnemann, *SafeKick*

Brian Tarr, *Shell*

Gordon Tschritter, *Cobalt International Energy*

Rohan Vaishampayan, *Statoil ASA*

Aaron Zaidel, *Noble Drilling Services, Inc.*

CONTENTS

Chapter 4 Well Control Procedures

4.1 KICK PREVENTION, PREPARATION AND DETECTION

4.1.1 Abnormal pressure indicators / kick warning signs

"Abnormal pressure" is a term used to describe pressures in wellbores that are greater than the expected, naturally occurring hydrostatic pressure.

Normal pressure is equivalent to the hydrostatic pressure generated by a column of seawater that has the normal chloride content for a specified geological region. Normal pressure is also often expressed in terms of a "normal pressure gradient". A normal pressure gradient could be between 0.433 to 0.468 psi per foot (9 ppg), depending on area.

"Abnormal pressure" is a pressure greater than the hydrostatic pressure of a column of water. An abnormal pressure gradient is a pressure gradient greater than the local water gradient.

In terms of equivalent mudweight, an abnormal pressure gradient or simply "abnormal pressure" is a formation pressure gradient greater than approximately 9.0 pounds per gallon (ppg). Common drilling indicators that may indicate that an abnormal pressure region is being approached include:

- Increase in background, and especially connection gas units;
- Drilling break, i.e. rate of penetration increase or decrease (depending on the drill bit type);
- Decrease in pump pressure or PWD;
- Increase in stroke rate corresponding to decrease in pump pressure;
- Sudden torque increase;
- Change in mud chlorides;
- Change in mud properties, especially viscosity;
- Distinct change in cuttings – shape, size, volume;
- Increase in BOP stack temperature (if equipped with sensor);
- Change in resistivity or change in sonic velocity (if LWD tools are in the string);
- Other indicators that can be calculated by pore pressure experts.

The indicators above are not positive proof of a kick but indicate that an underbalanced situation is likely. In some circumstances, observing one or more of these indicators may be sufficient to justify a flow check.

4.1.2 Abnormal pressure detection complications

Detecting abnormal pressure indicators can be complicated in deepwater due to:

Lag time for gas units and cuttings increases in deepwater and reduces the timeliness of this data for detection purposes.

Due to the cooling effect of a long riser, surface flowline mud temperature is not an effective tool in assessing formation temperature or abnormal pressure.

Downhole, real-time monitoring tools installed in the BHA can greatly assist in overall determination of EMW and pore pressure. Downhole tools include:

- Pressure While Drilling (PWD);
- Logging While Drilling (LWD);
- Real-time pore pressure measurement for actual pore pressure identification.

4.1.3 Kick indicators

Indicators that a kick is present are similar in surface BOP stack drilling operations, although environmental effects such as pitch, roll and heave motions (due to weather, crane activity, etc.) can significantly impact pit level and mud return detection methods. Two or more level sensors can be placed in each active pit that is subject to pitch and roll effects and connected to a pit volume totalizer (averaging technology) to reduce this effect. The location of the sensor(s) is also important to minimize effects, i.e., center for single sensor, near edges or corners for two sensors, etc.

There are multiple potential signs of a kick but only three [3] are positive indicators:

- Increase in flow out (when drilling)* or continued flow during connections after the pumps are shut off;
- Increase in surface pit level/volume (when drilling) or improper hole fill (when tripping);
- Positive flow check.

*Due to the difficulties of reliably detecting small increases in return flow while drilling, a slow feeding influx may only be detected by a positive flow check or by continued flow at the next connection.

4.1.3.1 Flow checks

The way to positively identify a kick is to turn off the pump, wait for the well to stabilize, and, if possible, observe the annulus. If the well flows when no liquid is being pumped, it is a strong indication that a kick is in progress. The driller may decide to perform a flow check if any of the indicators previously discussed occur.

Determining whether the well is actually flowing because of a kick can be made difficult due to other factors:

- Charging pumps that did not shut down when the rig pumps were turned off;
- U-tubing of fluid that is heavier in the drillpipe than the annulus. An indication of U-tubing would be that the rate of flow decreases measurably in a short time.
- When the pumps are brought up to speed after a connection, certain formations take fluid due to the increased equivalent circulating density (ECD) while circulating. When the pumps are shut-off for a connection or a flow check, the formation gives back “extra” mud which could be interpreted as a kick. This “ballooning” effect is most pronounced in deepwater operations where the formations are not as structurally competent as they are on land.

The interpretation of the overall situation is complicated and may be challenging. Because of this, ballooning should be treated with added caution. All unexpected flow including suspected ballooning must initially be treated as a kick and the well must be shut in.

Procedure for a Flow Check When Circulating

- Alert the crew;
- Pick up the top drive to a predetermined height and space out to place the string with the uppermost tool joint above the rig floor;
- Stop rotating;
- Shut off the pumps (including the boost pumps);
- For an extended flow check, after the return flow is observed to stop, switch the returns to the trip tank;
- Observe the well for flow.

NOTE: While it is common to line the well up on the trip tank to perform a planned flow check, this should not be the first course of action if the well is flowing. The well should immediately be shut in.

4.1.4 Mud density

See also: Well Planning, 1.3, Drilling Fluid Considerations

In deepwater, it is not generally possible to drill with enough mud density to keep the well over-balanced upon loss of the riser drilling fluid (“riser margin”).

Synthetic-based muds (SBM) and oil-based muds (OBM) have different compressibility and thermal expansion properties than water-based fluids. As a result, surface mud density alone may not be an accurate measure of downhole density and hydrostatic pressure. This includes long deepwater risers with their associated low temperatures as well as significant use of synthetic fluids in deepwater. These density differences should be considered in well planning and when changing from one type of fluid to another.

4.1.5 Mud viscosity

Viscosity increase in choke and kill (C&K) lines due to length and low temperature can mask shut-in casing pressure (SICP). This effect is increased with synthetic muds that have high viscosity at low temperature. Kick detection may be difficult, as the well may flow during flow checks, but have no shut-in casing pressure.

The C&K lines can be circulated several times per day to reduce the potential for settling of solids (unless they contain a clear fluid).

Due to high gel strengths, especially with synthetic muds, options include, isolating the wellbore and breaking circulation by pumping across the BOP stack with fresh mud prior to kick removal operations.

4.1.6 Drilled cuttings

Loading the annulus with cuttings could adversely impact the pressure applied to the casing shoe. This can lead to lost returns and, depending on loss rates, an underbalanced condition in the wellbore. Boost lines assist in increasing lost annular velocity due to increased annular capacity between the drillpipe and the riser, and can assist with cuttings removal.

4.1.7 Pre-kick preparation

Preparation for a kick includes:

4.1.7.1 Casing Shoe

- Measure the pressure integrity of casing shoes, i.e., by leak-off/integrity tests;
- Post both ppg equivalent and associated maximum surface pressure for the mudweight in use at the choke control panel;
- Update this pressure periodically and when drillstring, mud property or other changes occur which may affect pressure loss.

4.1.7.2 Slow circulating rates (also referred to as slow pump data)

- Post slow pump data (for at least two pumps at three different reduced pump rates) on both drillpipe friction loss and both C&K Line Friction pressures (CLFP);

- Take pressure readings on two separate gauges to guard against gauge failure;
- Note the strokes pumped and the pressure required to break circulation the first time, and record this value for use in kick detection and circulation procedures. Also record the corresponding flow show return percentage rate. Ensure that the cuttings in the hole and riser do not affect slow pump data;
- Additional methods can be employed at the time of the kick to update this data, i.e., using the static C&K line or subsea BOP pressure sensor (See 4.4: Kick circulation).

Note: Slow pump test rates should represent anticipated kill rates, which may be as low as 1-2 bbl/min in deepwater.

4.1.7.3 Choke and kill line friction pressures

- Use CLFP to help establish initial circulating casing pressure;
- Measure and record pressure losses with low circulation rate through the lines in parallel.*

*One option to reduce friction losses during well control in deepwater wells is to circulate the kick using both the choke and kill line (see 4.4.5, Number of C&K lines).

4.1.7.4 Kill sheet

Maintain an up-to-date kill sheet designed for subsea BOP. Also update the kick tolerance calculations daily.

4.1.7.5 Float valve

- When removing the top drive from the drillstring, Using a float valve in the BHA helps to prevent backflowdrillstring;
- Using a float valve helps to guard against backflow through the drillpipe during an emergency disconnect event and/or failure of the shear rams to seal;

Note: Flow up from the drillpipe can impede the ability to stab a safety valve. Develop procedures and drills to stab the top drive using the lower valve as the stabbing valve. Ensure that the correct connects are available on the drill floor and that the OD of the valve is such that it can pass through the BOPs, wellhead and wellbore casing.

4.1.7.6 Mud gas separator

- Ensure that the maximum liquid and gas handling capacity is known;
- Compare these figures to the maximum anticipated gas rates that would result from planned well control procedures and well and C&K line geometry (i.e., pumping rate, design kick.);
- Ensure that the maximum pressures for associated fluid weights in the liquid leg for the mud gas separator (MGS) are posted at the choke panel (This also includes wellbore produced fluids such as condensates);

Have a documented plan in place to either bypass the MGS overboard from the choke manifold or a hi-fold or to a flare boom, or shut in the well at the choke manifold if the MSG approaches being overloaded.

4.1.7.7 Diverter

- Keep the diverter insert packer installed and locked except when handling BHA larger than the manufacturer's stated diameter capacity;
- Post the diverter element status (in/out) at the drillers console;
- Ensure that the default lineup for flow path (for diverting operations) is overboard and not to the MGS (if so equipped).

4.1.7.8 Choke manifold

- The choke manifold should be checked tourly by the drill crew to ensure that it is properly lined up. The proper choke manifold lineup should be posted on the drill floor;
- Any change to the lineup during a tour should be communicated to the driller who will notify his relief.

4.1.7.9 Designated hang-off ram

- Identify designated hang-off ram;
- If it is a variable-borehole ram (VBR) type, post the hang-off capabilities for the various DP sizes in the hole;
- Ensure that there is sufficient clearance between the designated hang-off ram and the shear rams to allow the pipe to be cut on the tube (and not on a connection);
- Specify if rams are to be locked after closure (if independent locks);
- In deeper wells, the string weight could exceed the capacity of the hang-off ram. A plan must be in place to address this situation.

4.1.7.10 Personnel drills

- Perform BOP drills (pit and trip) regularly, including tool joint space-out;
- To ensure crew competency during non-routine events, consider having crews perform "stripping drills" and simulated "emergency disconnect" drills (if dynamically positioned) prior to drilling out of the casing shoes;
- The drill crew should check the choke manifold every hour to ensure that that it is properly lined up.

4.1.7.11 Other pre-planning

- All duties should be pre-assigned prior to a well kick;
- A BOP space-out diagram should be posted in the driller's house in sight of the driller;
- Step-by-step procedure(s) for shutting-in the well should be posted;
- Emergency disconnect procedures should be posted;
  - The shallow gas response procedure (when applicable) should be posted near the BOP / diverter panel;

- Schematics for the choke manifold, standpipe manifold, diverter and overboard valves should be available.
- Results of fingerprinting tests (when conducted) should be available for reference.

4.2 WELL CONTROL PRIOR TO BOP INSTALLATION (SHALLOW HAZARDS)

Shallow hazards are adverse drilling subsurface conditions that may be encountered prior to the setting of the first pressure containment string and the emplacement of the BOP upon the well. Prior to this there is no way to shut the well in.

“Shallow” is commonly understood by the industry to be the interval above the setting depth of the first pressure containment string.

Of particular relevance to the safety of the rig and the long term integrity of the well, therefore, is the potential presence of shallow gas and potential for shallow water flow (SWF).

See Chapter 2, Well Planning & Rig Operations, Section 10, Shallow Hazard Considerations, for more information.

4.2.1 Origins of shallow hazards

Shallow water flows (SWF) or shallow gas flows can be a problem when drilling with seawater with returns to mudline before the BOP and riser are installed.

While pressurized zones may also be encountered after the BOP is set, the difficulty of dealing with them is less if they can be shut in.

Pore pressure of shallow sands can be as high as 80-90% of overburden. Furthermore, gas may be found with shallow water flows, and is likely solution gas. Higher hydrostatic pressure in deeper water leads to higher gas content. In some cases, the flow may even be predominately gas.

Shallow gas generally occurs as normally pressured accumulations in shallow sedimentary formations with high porosities and high permeability. ”Structural” overpressures may exist where the sands are relatively thick or tilted and can require higher mudweights even though they are not abnormally pressured.

Flow rates can range from very low (near levels of detectability) up to several barrels per minute, and often contain significant amounts of sand.

4.2.1.1 Consequences of shallow hazards

The likely consequences of sustained shallow water flow include:

- Hole erosion;
- Post-cementing annular flow and broaching, crater formation;
- Wellhead subsidence;
- Loss of well and/or conductor/template support.

Additional consequences associated with a shallow gas flow include:

- Shallow gas blowout;
- Loss of vessel stability;
- Fire and explosion.

While permeability of SWF zones can be quite high, in the order of darcies, the origins of overpressured shallow formations are of a geologic nature and include:

- Trapped salt water that is pressured by the overburden loading, which is known as undercompaction;
- Massive turbidite depositions during the last ice age along continental slope. The pore water may be fresh.

SWF may not be noticed at first as the zone may be cased off and cemented. The flow may be a delayed reaction after cement sets and/or may broach to the surface at a considerable distance from the wellbore. Hence, an ROV should be regularly used to monitor both the well and the vicinity of the well for evidence of flow.

4.2.2 Approaches to drilling potential shallow hazard zones

The primary control method is avoidance and prevention. This is particularly true for shallow gas using shallow hazard surveys. This is covered in detail in Chapter 2, Well Planning & Rig Operations, Section 10, Shallow hazard considerations.

4.2.3 Shallow Gas

4.2.3.1 Planning

Prior to starting drilling operations, the rig manager and the operator must assess the risk of shallow gas. The well plan and specific operating procedures must be reviewed in the light of this assessment. A strategic review of all available site survey and offset well data is necessary for the development of a