Transocean

Title:

WELL CONTROL HANDBOOK

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1 GENERAL

The purpose of this handbook is to ensure that Transocean Well Control policies and procedures are accurately understood and implemented throughout the fleet. All issues or questions about implementation of the policies and procedures in this manual should be resolved through the operations chain of command. The level of Authority required for specific operations is detailed in the manual; the chain of command is:

Offshore Installation Manager (OIM)
Rig Manager – Performance
Operations Manager - Performance (this authority may reside with Sector Managers in some areas)
Division Manager (or Designee)
Business Unit Director of Operations Performance
Senior Vice President of Business Unit (SVP of Business Unit)

Exemption to a procedure in the manual must be approved by all the parties above with final approval by the SVP of the Business Unit or his designate (normally the Business Unit Director of Operations and Performance). For information on the exemption process, refer to the CMS Manual (HQS-CMS-GOV) Section 5, Subsection 5, Management of Change.

The Headquarters Well Operations Group provides assistance and support for any issues about implementation of the policies and procedures in this manual.

2 WELL CONTROL POLICIES & PROCEDURES

On all Transocean Installations, it is the responsibility of the OIM (where OIM also means Platform Manager) to assure the implementation of the well control policies and procedures contained within the Company's management system.

Company personnel with well control responsibilities must understand and comply with the Company-approved well control policies and procedures. The Well Control Handbook is comprised of policies and procedures which describe the performance standards to meet the following policies:

Well Control - Incident Prevention and Management, Operations Policy and Procedures Manual, HQS-OPS-PP-01, Section 3.1.1:

Prevention and management of well control incidents must conform to the requirements detailed in the Well Control Manual and be carried out by competent, well control certified personnel.

Well Control – Equipment, Operations Policy and Procedures Manual, HQS-OPS-PP-01, Section 3.1.2.

All well control equipment must conform to the specification and testing requirements detailed in the Well Control Manual.

Procedures represent mandatory requirements to meet policies. Procedures are represented by statements that include the term “must” “will” or “shall.” **Procedures in bold type and shaded boxes are highlighted to focus responsible personnel on required key actions and decisions.**

Recommended Practices represent reliable knowledge and methods for a particular process or activity proven through experience. Because their application may be specific in nature they cannot always be applied as described, and therefore are not mandatory to follow, but they are strongly endorsed and supported by Corporate Management as the best way to perform a given task or process. Recommended practices when not specifically stated are represented by statements that include the term “should’ or “may.”

The OIM must review the well control requirements and emergency response procedures with the Operator Representative on the rig to ensure that the Company’s and Operator’s policies are consistent. They must report any differences to the Rig Manager Performance.

The procedures contained in this manual represent Transocean standards and must be complied with unless an approved Request for Exemption form is completed which describes alternative procedures that meet the intent of the corporate policies.

Agreed client requirements or local regulations that exceed Company requirements, must be complied with.

The responsibilities of Company personnel as described in this manual in no way reduces those of the Operator with regards to well control.

Any issues with the content of this manual should be brought to the attention of the Headquarters Well Operations Group through the SMART process. For details on the SMART process refer to the CMS Manual (HQS-CMS-GOV) Section 5, subsection 1.

1 PREPARATION PROCEDURES

1.1 Prior to spudding, it is the responsibility of the Rig Manager Performance, in conjunction with the OIM, to review the well program and ensure that well control issues have been addressed. This should include potential blowout/underground blowout situations and contingency plans. No well will be spudded or hole section started unless the Rig Manager Performance and OIM have reviewed the relevant information.

1.2 The OIM (person-in-charge) must ensure that either oilfield, metric or SI units have been selected and clearly communicated to all relevant personnel. Appropriate forms must be made available.

1.3 The distance from the rotary table to the pipe rams must be known at all times and a space-out diagram posted in the vicinity of the Driller's BOP panel. Drillers on floating rigs must be provided with tide charts.

1.4 As well as the measured depth (MD), the Driller must also know true vertical depth (TVD) measurements in order to calculate the correct kill mud weight and accurately complete the kill sheet.

1.5 The Driller (or his designee) must check all choke manifold, diverter and overboard valves for the correct line-up at the beginning of each tour and ensure correct safety valves and crossovers are prepared and available on the drill floor.

1.6 Slow circulation rates must be taken:

- If practical, at the beginning of every tour.
- Any time the mud properties are changed.
- Any time the bit nozzle configuration or bottom hole assembly (BHA) is changed.
- As soon as possible after bottoms-up from any trip.
- At least every 1000ft (305m) of new hole.
- After MAJOR mud pump or surface equipment changes/repairs.

1.7 Unless the following materials are at the rig available to use, drilling operations must be suspended:

Enough weighting material and associated chemicals to raise the mud weight of the hole and riser volume and a surface active system of 150 bbls (24 m^3) by at least 1 ppg (120 kg/m^3 or 0.12 sg).

Contingency LCM as outlined in the drilling programme.

Enough cement and additives to place at least 2 x 500 ft (2 x 150m) plugs in open hole.

1.8 After setting the initial casing string(s) or during workover operations, a minimum of two independent and tested barriers must be in place at all times. Upon failure of a barrier, normal operations must cease and not resume until a two barrier position has been restored. A barrier is defined as:

Any remote operated valve or set of valves that can be regularly pressure tested.

A known and monitored fluid column that exerts sufficient hydrostatic pressure to overbalance the pore pressure.

Any cement plug in the wellbore that has been suitably tested.

Any mechanical device installed in the wellhead, christmas tree, tubing, annulus or wellbore that has been suitably tested – either inflow tested or pressure tested to the maximum anticipated surface pressure.

Any other pressure sealing mechanism installed for the purpose of preventing flow of fluids from a well.

1.9 During relevant operations, well control drills must be held on at least a weekly basis with each crew. These drills must be logged in the I.A.D.C. report and should be routinely alternated. If the plan is to divert during drilling of surface hole, then a diverter drill must be held by each crew at the beginning of every tour.

1.10 The period between pressure tests of the BOP and related equipment (excluding blind/shear rams which must not exceed a maximum period between tests of 42 days) must not exceed a maximum of 21 days. Pressure testing must be conducted in accordance with the Company Well Control manual.

1.11 BOP and related equipment must be function tested every 7 days or during the first trip after the 7-day interval. The intent is that the test be done when practical near the 7th day and will depend on the type of operations being carried out or still to be carried out. The period between function tests must not exceed a maximum of 14 days.

1.12 A float (solid or ported) must be run while drilling and opening hole prior to setting surface casing or any time the posted well control plan is to divert. In addition, all drillstrings used below surface casing must include either a float valve or landing sub for a drop-in valve with the drop-in valve kept on the rig floor.

1.13 A minimum of one safety valve and one inside BOP with crossovers, to fit all connection sizes of tubulars in the drillstring, must be available on the drill floor at all times, including a circulating head and/or 'water bushing' when running casing. A proper means of handling must be provided to assist with its installation.

1.14 Over the years, equipment has been designed to conform to various standards. Each Installation must comply with the specification of the well control equipment (RP53, API 16D, etc.) and the revision level as was used in the original design and commissioning. If the equipment has been subsequently upgraded to another standard, then the new standard will apply.

1.15 Casing, wellheads and pressure control equipment must, as a minimum, meet the working pressure and temperature requirements determined by the maximum anticipated surface pressure and temperature for each well and be reviewed prior to spudding by the Rig Manager Performance.

1.16 If the well cannot be shut-in with the BOP, the well must be properly secured by establishing two known and tested barriers.

1.17 Automatic MAASP control devices must be disabled.

2 PREVENTION PROCEDURES

2.1 Kick Tolerance must be calculated by the Toolpusher as detailed in Section 2 of this manual (a spreadsheet is available on RIGCentral). Results of the calculation should be compared to the matrix in Table 1.2.1 for the required level of notification or approval. All results falling into the red shaded areas require Approval from Division Managers or their designate, Yellow cells require Operations Manager Performance to be informed and Green cells require OIM and Rig Manager Performance to be notified.

Actions for continuing operations with a limited kick tolerance shall be evaluated based on the capability of the rig crew, rig equipment and rig procedures to effectively detect an influx and shut in the well as soon as possible. A review of operators offset well analysis shall be done and mitigations planned accordingly.

Table 1.2.1, Kick Tolerance Matrix

	Floater		Bottom Supported	
Well type	Development	Exploration & Appraisal	Development	Exploration & Appraisal
> 50 bbls				
25 – 50 bbls				
< 25 bbls				

OIM and Rig Manager Performance Informed	**Operations Managers Performance Informed**	**Division Manager Approval or Business Unit Director of Operations Performance Approval**

Suggestions to minimize the influx size are listed below:

- Any kick tolerance limitations should be communicated to the drill crews. Prior to drilling out the casing shoe the drill crew should be fully prepared to implement the applicable procedures.
- Understand the client kick tolerance calculation. Note that for the 'kick intensity' the client typically uses the expected maximum pore pressure rather than the mud weight plus an additional 0.5ppg.
- If there is any indication of flow consider shutting in the well immediately rather than taking the additional time to conduct a flow check.
- Where a risk of swabbing exists consideration should be given to pumping out of hole.
- Establish a baseline reading and continually monitor for any variation in trends for gas, mud, cuttings and drilling parameters. Tool Pusher and client personnel should be in constant communication with the mud logging unit and the well site geologist (where available)
- Whenever possible, limit circulation to a single active pit. Strictly enforce pit management, and carefully monitor for any discrepancies during trips.
- Consider extending the flowcheck period when using oil / synthetic oil based mud.
- Consider fingerprinting the flowback trend having shut off the pumps for a connection. Establish a baseline and closely monitor for any variation in this trend during subsequent connections.

2.2 All drilling breaks must be flow checked.

2.3 The hole must be kept full at all times using a trip tank or a calibrated pit. Accurate hole fill records must be kept during trips. The on-tour Toolpusher should be on the rig floor for a minimum of the first 10 stands whilst tripping out of open hole or until the bit is inside casing. If the hole does not take the correct volume of mud, or if the Driller has any doubt, the pipe must be run immediately and cautiously back to bottom and bottoms-up circulated.

2.4 When tripping pipe, flow checks must be performed at the following times:

- At the bottom of the well before any trip out of the hole.
- At the lowest casing shoe.
- Anytime the hole displacement is incorrect during a trip.
- Anytime the Driller (or the person performing the Driller's function) has any concerns regarding the well status.
- If continuous volume monitoring of the hole volume is not possible, then a flow check must be made, prior to pulling the HWDP or Drill Collars through the BOP's.

2.5 Boosting of the riser annulus during tripping operations is not a routine operation due to the potential for this practice to reduce early kick detection and thereby increase the volume of any influx taken during the operation.

For this reason, if it is considered necessary to boost during tripping operations the preferred method should be to stop tripping and flow check prior to commencing the boosting operation. Once boosting has been completed a flow check must be made and the well confirmed static prior to continuing the trip.

Should a rig plan to boost while continuing to trip, the Rig Manager must be satisfied that the rig can safely execute the task.

When there is no open hole exposed the manager must be satisfied that the integrity of the barriers involved, such as mechanical or cement plugs, or cemented liners and casing strings have been suitably tested.

Where open hole exists a Task Risk Assessment should be used to ensure that kick detection will not be compromised and the following aspects must be fully addressed:

- There must not have been any well control or hole problems in the exposed open hole.
- Where potential hydrocarbon-bearing zones are present, the reservoir characteristics and formation behavior must be known and understood.
- The current overbalance or trip margin must be known and considered adequate.
- In the case of an exploration well, sufficient data must have been collected to meet all of the above requirements. Even then, extreme caution should be exercised.

- Pit and flow line instrumentation settings must be sensitive enough to detect an influx while lined up to an active pit instead of the trip tank.
- Fluid transfers involving the active pit must not be made while tripping in this manner.
- If it is proposed to close blind/shear rams in order to isolate the open hole and boost while tripping through the riser then the specific hazards related to this practice must be included in the risk assessment.

2.6 Boosting the riser while pumping out of the hole may be permitted, under known conditions, and with similar precautions taken as listed above.

2.7 Any time a trip is interrupted the hand tight installation of a safety valve is required.

2.8 When lost circulation occurs and cannot be regained through the drillpipe, the annulus must be filled with the lightest fluid available (usually water) and the volume recorded.

2.9 Tripping out of the hole without full returns is potentially hazardous and will only be permitted under known conditions and with the approval of the Operations Manager Performance. The SVP of the Business Unit may decide that this decision must be made at the Business unit level. Such permission may be granted, in advance, on a well-by-well basis. This procedure does not apply to stable 'seepage' losses of less than 20 bbls/hr (3 m^3/hr).

2.10 No more than 6 joints of casing will be run without filling, irrespective of the type of float equipment in use.

2.11 A flow check must be conducted any time the Driller has doubt about the stability of the well.

2.12 The start of a well test or clean up must not be conducted at night without prior approval, following a risk assessment, of the Operations Manager performance.

2.13 If rig power failure occurs then shut the well in. The volumetric technique may have to be used if influx migrates while attempting to restore power. Always assess extent of power failure before deciding on whether to resume the kill using auxiliary or back up systems, e.g., cement pump.

3 DETECTION PROCEDURES

3.1 It is the responsibility of the Driller (or person performing the Driller's role) to shut-in the well as quickly as possible if a kick is indicated or suspected.

3.2 Drillers must be instructed in writing on whether to shut-in or divert if a well kicks while drilling surface hole (as indicated in the drilling programme).

3.3 Wells must be shut-in using the procedure described in Section 5 of this manual. A step-by-step procedure for shutting-in the well must be posted in the vicinity of the Driller's panel.

3.4 If an influx is confirmed, the operator representative and the Rig Manager Performance must be notified immediately.

4 REMEDY PROCEDURES

4.1 The topdrive (or kelly) must be used for well control operations with a kick assembly kept available as an alternative. The kick assembly must be used if:

- The anticipated surface pressure exceeds the safe working limits of the topdrive (Kelly) or associated equipment.
- The drillstring compensator (DSC) is not operational.

4.2 When a kick is being displaced from the well, constant bottom hole pressure must be maintained. Priority must be given to maintaining constant BHP even if the MAASP is exceeded. However, all efforts should be made to minimize the risk of MAASP being exceeded.

4.3 When the well is shut-in due to a kick, reciprocation or rotation of the drillpipe is not permitted unless prior approval has been received from the Business Unit Director of Operations Performance.

4.4 Stripping through ram preventers must only be permitted with surface stacks and then only if there are greater than two appropriately sized sets of rams available for use.

4.5 The OIM must complete a Well Control Event Report (WCER) and send it to the Rig Manager Performance for review after any type of well control operation. The report must include an account of any equipment-related problems that may have occurred during the well control operation. Rigs equipped with a computerized kick detection system should have a printout of the recorded data from the well kick attached to the report. A copy of the report must be forwarded to the Well Operations Group and regional training center. A blank format of WCER is available in Appendix Section 10 Subsection 2.4. Excel sheet for the WCER can accessed at link below.

http://www.rigcentral.com/hqs/pt/well_operations_group/Well_Control.asp

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1 SVP OF THE BUSINESS UNIT / BUSINESS UNIT DIRECTOR OF OPERATIONS PERFORMANCE (I)

The SVP of the Business unit / Business Unit Director of Operations Performance are responsible for ensuring that the well control policies and procedures are being met.

2 DIVISION MANAGER / OPERATIONS MANAGER PERFORMANCE (D)

Division Managers and Operations Managers Performance are responsible for ensuring that the Well Control policies for Incident Prevention and Management and Equipment are being achieved. They must satisfy themselves that the Rig Manager Performance and OIM understand the well control policies and procedures required to operate and safely manage their installation. SVP of the Business units and Division Managers must monitor performance and conduct independent assessments which include Performance Monitoring Audit and Assessments (PMAA) and well control equipment hardware audits, as they deem necessary.

3 RIG MANAGER PERFORMANCE (D)

Rig Managers Performance are responsible for monitoring and verifying the effective implementation of the well control policies and procedures by ensuring that all personnel involved with well control are competent to fulfill their responsibilities. He must inform both the Operations Manager Performance and the Business Unit Director of Operations Performance anytime that Well Control Operations have commenced on the rig.

4 OFFSHORE INSTALLATION MANAGER (OIM) (D)

- The OIM is responsible for overall safety of the Installation and all the personnel onboard.
- Convenes a pre-kill meeting in order to establish and agree upon the kill strategy to be pursued. Participants will be the Senior Toolpusher, the Operator Representative and any other relevant personnel.
- Delegates the responsibility for the well control operation to the Senior Toolpusher, if required.
- Prepares the Installation for evacuation in accordance with the level of alert.
- Informs all shore-based parties as required by the emergency response procedures.
- Arranges assistance as the situation may require.

- Assigns someone to maintain a log of events.
- Keeps non-essential personnel updated on a regular basis with respect to well status.

5 TOOLPUSHER (D)

- The Senior Toolpusher is the Transocean Person-in-Charge of the kill operation (if so delegated). The Senior Toolpusher may delegate to the Toolpusher, as required.
- Ensures that the crew is organized and prepared for killing the well.
- Liaises with the Operator Representative throughout the well kill operation.
- Operates the choke during well kill operation (or his designee).
- Communicates the status of the well kill operation to the OIM on a continuous basis.

6 DRILLER (D)

- The Driller is responsible for monitoring the well at all times, identifying when the well is to be shut-in and shutting-in the well quickly and safely.
- Once the well is shut-in calls the Person-in-Charge.
- On floating rigs, calls the Subsea Engineer to the drill floor initially.
- Monitors the key parameters (e.g. pressures, volumes and time) and designates a crew member to record same during the kill operation.
- Operates the mud pump during the kill operation.
- Implements instructions from the Toolpusher.

7 ASSISTANT DRILLER/DERRICKMAN (D)

- Lines up the mud gas separator and vacuum degasser.
- Lines up the mixing pumps and bulk barite system for weighting up the mud and stands by for specific instructions from Toolpusher and Mud Engineer.
- Once pumping starts, keeps constant check on mud weight and pit volumes and reports these to the Driller.
- Ensures the kick assembly is ready to be picked up, if required.

8 FLOORMEN (I)

- Follow Driller's instructions.

9 OPERATOR REPRESENTATIVE (D)

- It is suggested that, during the kill operation, the Operator Representative remains at the remote choke control panel in order to observe and discuss the operation with the Senior Toolpusher.
- Organizes assistance from the Operator's shore-base, as required.
- Organizes sub-contractors, as required.

10 MUD ENGINEER (D)

- Reports to the pit room to check the Assistant Driller's/Derrickman's preparations and coordinates the building and maintenance of the required mud system.
- Checks and confirms all volumes of mud and chemicals on board. Monitors mud properties and return flow for any abnormalities.
- Checks and confirms calibration of mud balance

11 BARGE SUPERVISOR/CAPTAIN (D)

- Ensures that the bulk system is charged and ready for use.
- Stands by in the control room or bridge in preparation for responding to an emergency situation.
- Notifies the standby vessel to move into evacuation position.
- Ensures readiness of the evacuation equipment.

12 CRANE OPERATOR (D)

- Prepares to release the workboat, if alongside.
- Ensures that doors and hatches are closed, where necessary.
- Assists mud mixing operations.

13 ROUSTABOUTS (I)

- Report to mud pits/sack room to assist the Assistant Driller/Derrickman.

14 SUBSEA ENGINEER (D)

- Reports initially to the drill floor to check functions and operating pressures on the BOP control panel. He/she must be present at the control panel in case of equipment problems.

15 MUD LOGGING ENGINEERS (D)

- Report to the mud logging unit and continuously monitor the circulating and drilling systems during the well control operation.
- Review all data and report any abnormalities to the Operator Representative, Driller and Senior Toolpusher.

16 CEMENTER (D)

- Ensures that the cement unit is tested and ready for operation.
- Ensures slurry formulation and additives are ready in case a cement plug is required.
- Operates the cement unit, if required, under the instruction of the Senior Toolpusher.

17 ELECTRICIAN/MECHANIC (D)

- Standby for possible instructions.

18 CONTROL ROOM OPERATOR (D)

- Ensures that rig stability is maintained and monitors safety systems (Gas Alarms, etc.) during well control operations.

19 RADIO OPERATOR (D)

- Logs all calls, telexes and faxes and keeps the lines open for the Operator Representative, OIM and any other personnel authorized by the OIM to use the communications system.
- Assists the OIM and Operator Representative in all matters of communication.

1 GENERAL

As a minimum requirement, personnel must successfully complete a recognized Well Control Training course as required by the Human Resources Policies and Procedures, HQS-HRM-PP-01, Section 6, Subsection 1, Required Training.

2 WELL CONTROL TRAINING REQUIREMENTS

Personnel listed in the table below will successfully complete a Transocean well control course or equivalent external course determined by the Business Unit / Division Training Manager to meet Transocean standards. IADC WellCap is the company standard for well control training. Personnel are required to successfully complete IADC WellCAP training and pass the course exam to obtain the required certification.

Any internationally recognized well control certification (i.e., IWCF, MIGAS, etc.) contractually required by a client or regulatory authority can be taught internally or externally at the discretion of the Business Unit / Division Training Manager and will be recognized as compliant with this policy.

Table 1.4.1, Well Control Training Requirements

Position	Well control course every 2 Years	Well control course every 4 Years	IADC WellCAP Fundamental	IADC WellCAP Supervisory
Offshore				
OIM	✓			✓
Senior Toolpusher	✓			✓
Toolpusher	✓			✓
Driller	✓			✓
Assistant Driller	✓		✓	
Derrickhand	✓		✓	
Drilling Supervisor	✓			✓
REP	✓			✓
Subsea Supervisor (primary Subsea on installation)	✓		✓	
Onshore				
Operations Manager Performance		✓		✓
Rig Manager (Performance)		✓		✓
Operations Engineer		✓		✓

3 REFERENCE

3.1. HUMAN RESOURCES POLICIES AND PROCEDURES, HQS-HRM-PP-01, SECTION 6, SUBSECTION 1, REQUIRED TRAINING.

The two factors that most influence well planning are formation pressure and formation strength and represent the limits within which drilling operations are able to continue – the "drilling window". Accurate estimates of both are required in order to optimize well design and perform operations in a safe and efficient manner.

1 HYDROSTATIC PRESSURE

Hydrostatic pressure is the pressure exerted by a column of fluid and is calculated by multiplying the density gradient of the fluid by the true vertical depth at which the pressure is being measured. Most well control calculations revolve around this basic equation:

Hydrostatic Pressure = Fluid Density Gradient x True Vertical Depth

Throughout this manual equations are presented using the three units of measurement used by the Company world-wide, namely: Oilfield, SI and Metric. To convert a mud weight into a pressure gradient a conversion factor is required as follows:

Oilfield units: P_h (psi) = MW (ppg) x 0.052 x TVD (ft)

SI units: P_h (kPa) = MW (kg/m^3) ÷ 102 x TVD (m)

Metric units: P_h (bar) = MW (kg/l) x 0.0981 x TVD (m)

where, P_h = Hydrostatic pressure
MW = Mud weight
TVD = True vertical depth

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1 PRESSURE REGIMES

1.1 NORMAL PRESSURE

Normal formation pressure is equal to the hydrostatic pressure of the 'native' water extending from the surface to the subsurface formation and results when the rate of sedimentation allows the water between the pore spaces to flow freely during compaction.

The degree of hydrostatic pressure exerted by the 'native' water is mainly dependent on its salinity and, to a lesser extent, dissolved gas and temperature. 'Normal' formation pressure gradients of as high as 0.515 psi/ft (11.65 kPa/m, 0.117 bar/m) have been encountered in formations adjacent to salt domes.

Figure 2.2.1, Normal Pressure by Region

Formation Water	(psi/ft)	(kPa/m)	(bar/m)	Region
Fresh Water	0.433	9.79	0.098	Rocky Mountains
Salt Water	0.442	10.00	0.100	Most Sedimentary Basins
Salt Water	0.452	10.22	0.102	North Sea, S. China Sea
Salt Water	0.465	10.52	0.105	Gulf of Mexico (GOM)
Salt Water	0.478	10.81	0.108	Some areas of GOM

1.2 SUBNORMAL PRESSURE

Subnormal formation pressure is defined as any formation pressure that is less than 'normal' pressure. A subnormal formation pressure gradient is any gradient less than the 'native' water gradient and can be due to reservoir depletion, surface elevation higher than water table elevation, temperature reduction in an isolated fluid system, tectonic activity and osmosis.

1.3 ABNORMAL PRESSURE

Abnormal formation pressure is any formation pressure that is greater than 'normal' pressure. An abnormal formation pressure gradient is higher than the pressure gradient of the 'native' water and is most commonly caused by the undercompaction of shales, claystone diagenesis, tectonic activity (e.g. faulting, uplift, salt diapirs) and structural features (e.g. an impermeable cap rock overlaying a gas reservoir).

1.4 TRANSITION ZONE

The transition zone is the formation in which the pressure gradient begins to change from that of a normal gradient to one of subnormal or, more usually, abnormal gradient.

The depth over which the pressure regime changes is a function of the sealing capability (vertical permeability) of the formation. Since perfect seals of zero permeability rarely occur (except, for example salts and anhydrites), transition zones are normally present.

The thickness of the transition zone depends on the vertical permeability of the formation, the differential pressure caused by the adjacent formation and the age of the overpressure (i.e. the time available for fluid flow/pressure transmission to occur).

The presence of the transition zone is very important in formation pressure evaluation. Formation properties in this zone often show a change away from normally pressured depth related trends and the magnitude of the change in the trend can sometimes be used to estimate the change in the formation pressure gradient.

2 PREDICTION AND EVALUATION

2.1 PREDICTION

The table below summarizes the various methods used in predicting pore pressure.

Figure 2.2.2, Methods for Predicting Formation Pressure

Data Source	Pressure Data/Indicators	Stage of Well
Offset Wells	Mud loggers report Mud weights used Kick data Wireline log data Wireline formation test data Drill stem test data	Planning (also used for comparison while drilling)
Geophysics	Seismic (interval velocity)	Planning
Drilling Parameters	Drilling rate Drilling exponents Other drilling rate methods Torque/Drag MWD/LWD/FEWD	While Drilling

Figure 2.2.2, Methods for Predicting Formation Pressure (con'd)

Drilling Mud Parameters	Gas levels Flowline mud weight Flowline temperature Resistivity, salinity and other mud properties including lime	While Drilling (delayed by the lag time)
Cuttings Parameters	Bulk density Shale factor Volume, shape, and size	While Drilling (delayed by the lag time)
Wireline Logs	Sonic (interval transit time) Resistivity log Density log	After Drilling
Direct Pressure Measurements	Wireline tests (RFT/MDT) Drill stem tests	Well Testing or Completion

2.2 EVALUATION WHILE DRILLING

The aim of formation pressure evaluation while drilling is to determine the optimum mud weight needed to contain any formation pressures encountered, while maximizing rates of penetration and minimizing lost circulation, differential sticking and hole stability problems. To achieve this, formation properties have to be closely monitored in order to detect any changes that may indicate the transition from one pressure regime to another.

Abnormally pressured zones may exhibit several of the following properties when compared to normally pressured zones at the same depths:

- Higher porosities
- Higher temperatures
- Lower formation water salinity
- Lower bulk densities
- Lower shale resistivities
- Higher interval velocities
- Higher hydrocarbon saturations

Any parameter which reflects changes in these properties may be used as a means of evaluating formation pressures. It should be remembered that the above properties also vary with differing lithologies and this must always be taken into account when interpreting changes in drilling and mud parameters.

Drillstring tools such as LWD and FEWD tools are now able to continually log and help identify high and low pressure zones.

2.3 EVALUATION AFTER DRILLING

2.3.1 ELECTRIC LOGGING

After drilling a hole section, the formations may be electrically logged to evaluate their physical characteristics and hydrocarbon potential. Direct formation pressure measurements (only in permeable formations) are of particular importance to well control.

In impermeable (e.g. shale) formations, the sonic log is usually the best log for quantitative pressure evaluation as it is relatively unaffected by changes in hole size, formation temperature, and formation water salinity.

2.3.2 DRILL STEM TEST (DST)

Pressure gauges are normally run with the DST string to calculate reservoir characteristics such as formation pressure, permeability, skin damage and productivity index.

3 EFFECTS OF POROSITY AND PERMEABILITY

The essential properties of reservoir rocks are their porosity and permeability - these properties will determine how much and how quickly a kick will enter the well. The porosity provides the storage space for fluids and gases and is the ratio of the pore spaces in the rock to the bulk volume of the rock. This is expressed as a percentage, and reservoir rocks commonly have porosities ranging from 5% to 30%.

Formation permeability is a measure of how easy a fluid will flow through the rock and depends upon the number, size and degree of interconnection between the pore spaces. Shales may have a similar porosity as sandstones but because the pores are not well connected, fluid is unable to travel through the formation. Permeability is expressed in Darcys and in reservoir rocks, ranges from a few milliDarcys to several Darcys.

A kick will enter a wellbore faster from rock having a high permeability. It is possible, therefore, to drill under balance in formations with very low permeability, such as shales, because the entry of the influx into the wellbore is very slow.

1 DESCRIPTION

In order to plan and drill a well it is necessary to have some knowledge of the formation strength/fracture pressures of the formations to be penetrated. The maximum volume of an influx that can be contained by the open hole is dependent on the fracture gradient. In the absence of leak-off test (LOT) data, an estimation can be made using Daines' method (which itself is a refinement of Eaton's method).

2 PREDICTION AND EVALUATION

2.1 LEAK-OFF TEST (LOT)/FORMATION INTEGRITY TEST (FIT)

A leak-off test (LOT) determines the pressure at which the formation begins to take fluid. This test is conducted after drilling out about 10-15 ft (3-5 metres) of new hole below the shoe of any casing intended for pressure containment.

Such a test will establish the strength of the formation at the shoe and the integrity of the cement job at the shoe, which is used to determine the maximum mud weight the open hole can withstand to reach the next casing point. For long open hole sections, the original leak-off test will not necessarily determine the weakest point in that section. In the event that a weaker formation has been drilled, a further leakoff test should be performed.

The exposed formation is usually tested to one of the following:

- A pre-determined pressure test that is below fracture pressure (FIT).
- Leak-off pressure (LOT).
- Breakdown and injection pressure (Injectivity Test).

The test pressure should not exceed 70% of the minimum yield of the weakest casing, allowing for mud weight differential (inside/ behind the casing string).

Data obtained from LOTs should be treated with some caution. High or low temperatures will have an effect on mud properties such as density and rheology, thus introducing an element of error into the surface readings obtained during a LOT.

Using values obtained to calculate the maximum pressure the formation can temporarily handle, such as circulating out a kick, is acceptable. However, the ability of the formation to support pressure continuously may be adversely affected by changes in the hole profile or localised damage to the wellbore.

Conversely, the capability of the formation to withstand pressure may improve during the subsequent drilling of the section due to the build up of filter cake on the formation wall and temperature enhancement of formation strength. (Refer to Section 10 Subsection 7).

1 CASING SETTING DEPTHS

The choice of setting depths for all casing strings is a vital part of the well planning process. A casing string set too high may leave weak zones exposed in the subsequent open hole section, which are unable to support the mud weights needed to drill to the next casing point.

Initial selection of the setting depths is made with reference to the anticipated lithological column, formation pressure and fracture gradient profiles. From a well control aspect, it is necessary to determine whether these tentative setting depths give adequate protection against formation breakdown when a kick is taken. Formation strength required will depend on whether a large volume kick back to the casing shoe is being designed for or a “limited kick”. For the latter, kick tolerance calculations will need to be made.

2 MAXIMUM ANTICIPATED SURFACE PRESSURE

The Maximum Anticipated Surface Pressure is defined as the **maximum internal pressure that the BOP (and related equipment) will be reasonably subjected to while conducting the well operations.**

The Maximum Anticipated Surface Pressure must be calculated for each applicable section of the well and should not exceed the pressure rating of the BOP and all other associated equipment.

The maximum anticipated pressure at the BOP is typically calculated using a ‘worst case’ scenario assuming full evacuation of the drilling fluid to gas from the section TD to the BOP / wellhead.

While the assumptions used in this calculation can vary from client to client, Transocean’s preferred calculation method is detailed below:

1. Calculate the bottom hole pressure based on the maximum pore pressure expected to be encountered in the open hole section TD i.e. bottom hole pressure (BHP).
2. Calculate the fracture pressure at weak point i.e. the immediate casing shoe above the same open hole section. (As per Leak Off Test)
3. The Maximum Anticipated Surface Pressure is the **minimum** value obtained after subtracting the gas hydrostatic gradient from 1 and 2. (Assume a gas gradient of 0.1 psi/ft)

To allow a margin for bull-heading operations, the ideal situation is to have the BOP and associated well control equipment rated to a pressure at least 500 psi higher than the calculated Maximum Anticipated Surface Pressure.

NOTE: For development wells where a known and proven reservoir fluid gradient is available, the actual fluid gradient(s) may be considered instead of using a gas gradient of 0.1psi/ft.

Example Maximum Anticipated Surface Pressure Calculation

Depth of Wellhead / BOP below the RT	: 25ft
Casing size	: 13 3/8in
Casing shoe, TVD	: 8000ft
Fracture pressure EMW	: 15.7ppg
Next hole size	: 12.25in
Next hole section TD, TVD	: 10,000ft
Expected Max pore pressure at next section TD	: 15.0 ppg (@ 10,000 ft)
Gas Gradient	: 0.1psi/ft

1.	Bottom hole pressure (BHP)	= 10000 x 15.0 x 0.052 = 7800 psi
2.	Fracture pressure at 13 3/8” shoe	= 8000 x 15.7 x 0.052 = 6531psi
3a.	Internal pressure at wellhead/BOP (BHP minus gas to surface)	= 7800 – ((10000 – 25) x 0.1) = 6803 psi
3b.	Internal pressure at wellhead/BOP (Fracture pressure minus gas to surface)	= 6531 – ((8000 – 25) x 0.1) = 5734 psi

The Maximum Anticipated Surface Pressure is the minimum value of 3a and 3b above = 5734 psi.

NOTE: In the above example the surface pressure was limited by the fracture pressure (i.e. shoe strength). With a sufficient shoe strength, the maximum anticipated surface pressure will equate to the bottom hole pressure minus a column of gas back to surface.

The client may calculate maximum anticipated surface pressure using other methods that are based upon either (i) the partial evacuation of the wellbore contents to gas (or known and proven reservoir fluids) or (ii) based upon a limited kick volume. The maximum anticipated surface pressure value using these methods does not represent the worst case and will result in lower values than those calculated using full evacuation. When these alternative calculations have been used by the client the assumptions used to validate this data need to be carefully considered.

When the client provides a maximum anticipated surface pressure that is less than the one calculated by using the above calculation method the Rig Manager Performance should inform the Operations Manager Performance and ensure that the rating and the pressure testing of the BOP are acceptable for the hole sections to be drilled.

Only calculations based upon full evacuation should be considered for production casing strings or during well tests (DST) as a leak at surface in the production tubing would result in a 'gas to surface' scenario. **Under no circumstances should a well test be conducted if the BOP is not rated for a full column of reservoir fluid from the perforated interval back to surface**.

Spreadsheets to assist in the calculation of Maximum Anticipated Surface Pressure are available on the Well Operations Website at:

http://www.rigcentral.com/hqs/pt/well_operations_group/well_control1.asp

3 KICK TOLERANCE

Kick tolerance is defined as the maximum volume of kick influx (normally assumed to be gas) that can be safely taken into the wellbore and subsequently circulated out of the well without breaking down the formation at the open hole weak point (normally assumed to be the shoe). It is dependent on a number of factors which can change as a section is being drilled, e.g. mud weight, hole depth, BHA, hole geometry, formation pressure, influx type, etc.

There are a number of methods of calculating kick tolerance including some sophisticated kick simulators which take into account the formation deliverability and can predict the time the rig crew has to close in the well before the influx exceeds the kick tolerance limit. Due to their complexity, kick simulators are only recommended for use when the level of risk is considered critical based on the simple kick tolerance calculations outlined below.

Kick Tolerance Calculations

This is a simplified calculation and uses the following assumptions:

- The kick tolerance is calculated using a kick intensity of 0.5 ppg (60 kg/m^3, 0.06 kg/l).
- The influx is a single gas bubble and is at the bottom of the hole at the initial shut-in.
- Temperature changes, gas compressibility, solubility, dispersion and migration are ignored.

These assumptions are taken to simplify the calculation process and as a rule give a more conservative (i.e. smaller) kick tolerance.

The kick tolerance calculations consider two cases:

- At the initial shut-in conditions with the influx at the bottom of the hole.
- The top of the influx has been displaced to the open hole weak point (i.e. the shoe) with the original mud weight.

The following procedure must be used to calculate kick tolerance:

1. Due to the additional pressures acting on the wellbore during circulation in a kick situation, the Maximum Allowable Annular Surface Pressure (MAASP) must be reduced by an appropriate safety margin. Some of the causes for the additional pressure are:

   Annular friction losses – dependent on hole size, pipe size, fluid properties, etc.

   Choke operator error.

   Choke line friction losses (more for floating rigs if not compensated).

   The safety margin will be the sum of these pressures and should be deducted from the MAASP. This will determine the new maximum allowable annular surface pressure without breaking down the weak point formation before circulation is initiated:

Pmax = Plot – (MW(ppg) x 0.052 x TVDwp(ft)) – SM(psi) …. Oilfield Units
Pmax = Plot – (MW(kg/m^3) ÷ 102 x TVDwp(m)) – SM(kPa)… SI Units

Where,
Pmax = Maximum allowable annular surface pressure (psi or kPa)
Plot = Leak off pressure at the weak point (psi or kPa)
MW = Mud weight in use (ppg or kg/m^3)
TVDwp = True vertical depth of weak point (shoe – ft or m)
SM = Safety margin (psi or kPa)

2. The maximum allowable height of influx in the open hole can now be calculated:

$$\text{Hmax} = \frac{[\ \text{Pmax} - (\text{Pf} - (\text{MW} \times 0.052 \times \text{TVD}))\ ]}{(\text{MW} \times 0.052) - \text{Gi}} \quad \text{… Oilfield Units}$$

$$\text{Hmax} = \frac{[\ \text{Pmax} - (\text{Pf} - (\text{MW} \div 102 \times \text{TVD}))\ ]}{(\text{MW} \div 102) - \text{Gi}} \quad \text{…….SI Units}$$

Where,
Hmax = Maximum allowable vertical height of influx (ft or m)
Pf = Formation pressure (psi or kPa); mud weight plus 0.5 ppg (60 kg/m^3) for the kick intensity factor
TVD = True vertical depth of the hole (ft or m)
Gi = Influx gradient (psi/ft or kPa/m); assume 0.1 psi/ft (2.262 kPa/m) equivalent

3. The maximum allowable influx volume can be calculated for the initial shut-in conditions:

V = Hmax x (Ca / cos Atd)

Where,
V = Maximum allowable influx volume at initial shut-in conditions (bbls or m^3)
Ca = Annular capacity around BHA (bbls/ft or m^3/m)
Atd = Hole angle at the bottom of the hole (degrees)

Where (Hmax / cosAtd) is greater than the length of the BHA, then the maximum allowable volume should be calculated on the total capacity around the BHA and the remainder on the annular capacity around the drillpipe.

4. The second part is to calculate the maximum allowable influx volume for Hmax when the influx has reached the open hole weak point:

   Vwp = Hmax x (Cdp / cos Awp)

   Where,
   Vwp = Maximum allowable influx volume at the open hole weak point (bbls or m^3)
   Cdp = Annular capacity around the drill pipe (bbls/ft or m^3/m)
   Awp = Hole angle in the open hole below the weak point (degrees)

5. The volume determined in step 4 then has to be converted to the maximum allowable influx volume it would be at initial shut-in conditions using Boyle's Law:

   V' = Vwp x Plot / Pf

6. The true kick tolerance is the smaller of the two maximum allowable influx volumes at initial shut-in conditions (V and V') calculated in steps 3 and 5.

NOTE: If the kick tolerance for a swabbed kick (induced) is required, the value of Pf (Formation Pressure) should be taken as the value of the mud hydrostatic in use (i.e. the pressure of the swabbed in gas bubble is equal to the hydrostatic pressure of the mud column). This methodology gives a higher kick tolerance since no kick intensity is incorporated and should not be confused when dealing with the kick tolerance limits outlined below.

Example (Oilfield Units)

Casing Shoe – 13 3/8" casing	5,000'
LOT	13.5 ppg EMW
Hole angle at shoe	Vertical
Hole size	12 1/4"
Current hole angle	60 degrees
Current hole depth	11,000 ft MD / 9,000 TVD
BHA length / OD	600' / 8"
Drillpipe	5"

Mud weight	11.5 ppg
Annular back pressure at SCR	50 psi
Choke operator error	100 psi
Kick Intensity	0.5 ppg
Influx Gradient	0.1 psi/ft
Annular capacity around BHA (Ca)	0.0836 bbls/ft

Safety Margin to be applied:
SM = 50 + 100 = 150 psi

Revised Maximum Allowable Pressure (taking into account safety margin):
Pmax = Plot – (MW(ppg) x 0.052 x TVDwp(ft)) – SM(psi)
Where Plot = 13.5 x 0.052 x 5000 = 3510 psi

Pmax = 3510 – (11.5 x 0.052 x 5000) – 150 = 370 psi

Maximum Allowable Influx Height in Open Hole:

$$Hmax = \frac{[\ Pmax - (Pf - (MW \times 0.052 \times TVD))\ ]}{((MW \times 0.052) - Gi)}$$

Where Pf = (11.5 + 0.5) x 0.052 x 9000 = 5616 psi

$$Hmax = \frac{[\ 370 - (5616 - (11.5 \times 0.052 \times 9000))\ ]}{((11.5 \times 0.052) - 0.1)} = 273 \text{ ft}$$

Maximum Influx Volume at Initial Shut-In Conditions:
V = Hmax x (Ca / cos Atd)

V = 273 x (0.0836 / cos 60) = **45.64 bbls**

Maximum Influx Volume with Influx at Weak Point:
Vwp = Hmax x (Cdp / cos Awp)

Vwp = 273 x (0.1215 / cos 0) = **33.16 bbls**

Converting this Volume via Boyle's Law:
V' = Vwp x Plot / Pf

V' = 33.16 x 3510 / 5616 = **20.72 bbls**

Therefore, the actual Kick Tolerance (the smaller of V and V') is 20.72 bbls.

Example (SI Units)

Casing Shoe – 13 3/8" casing	1524 m
LOT	1619 kg/m^3 EMW
Hole angle at shoe	Vertical
Hole size	0.311 m (12 1/4")
Current hole angle	60 degrees
Current hole depth	3353 m MD / 2743 m TVD
BHA length / OD	183 m / 0.203 m (8")
Drillpipe	0.127 m (5")
Mud weight	1379 kg/m^3
Annular back pressure at SCR	345 kPa
Choke operator error	690 kPa
Kick Intensity	60 kg/m^3
Influx Gradient	2.262 kPa/m
Annular capacity around BHA (Ca)	0.0436 m^3/m

Safety Margin to be applied:
SM = 345 + 690 = 1035 kPa

Revised Maximum Allowable Pressure (taking into account safety margin):
Pmax = Plot – (MW(kg/m^3) ÷ 102 x TVDwp(m)) – SM(kPa)
Where Plot = 1619 ÷ 102 x 1534 = 24190 kPa

Pmax = 24190 – (1379 ÷ 102 x 1524) – 1035 = 2441 kPa

Maximum Allowable Influx Height in Open Hole:

$$Hmax = \frac{[\ Pmax - (Pf - (MW \div 102 \times TVD))\ ]}{((MW \div 102) - Gi)}$$

Where Pf = (1379 + 60) ÷ 102 x 2743 = 38698 kPa

$$Hmax = \frac{[\ 2551 - (38698 - (1379 \div 102 \times 2743))\ ]}{((1379 \div 102) - 2.262)} = 83.26 \text{ m}$$

Maximum Influx Volume at Initial Shut-In Conditions:
V = Hmax x (Ca / cos Atd)

V = 83.26 x (0.0436 / cos 60) = **7.26 m^3**

Maximum Influx Volume with Influx at Weak Point:
Vwp = Hmax x (Cdp / cos Awp)

Vwp = 83.26 x (0.0633 / cos 0) = **5.27 m^3**

Converting this Volume via Boyle's Law:
V' = Vwp x Plot / Pf

V' = 5.27 x 24190 / 38698 = **3.29 m^3**

Therefore, the actual Kick Tolerance (the smaller of V and V') is 3.29 m^3.

3.1 WHEN TO CALCULATE KICK TOLERANCE

The frequency of kick tolerance calculation is dependent on the nature of the well. In hole sections which kick tolerance is likely to be a critical factor the following should be considered:

- After a LOT, evaluate the kick tolerance at suitable intervals throughout the next hole section with the mud weight used at the start of the section.
- The kick tolerance should also be evaluated throughout the section with mud weights that are likely to be used.
- If the hole section contains areas of rapid pore pressure increases the kick tolerance should be re-evaluated at suitable intervals across the area of increasing pressure.
- If any factors that affect kick tolerance (such as mud weight) change as the section is drilled, the kick tolerance below that point should be re-evaluated to reflect that change.

3.2 KICK TOLERANCE HIGHLY DEVIATED OR HORIZONTAL WELLBORES

It is important to understand the effect which highly deviated or horizontal wellbores have on the available kick tolerance.

As the inclination of the wellbore increases the vertical height of the influx reduces. For a horizontal section, the vertical height of the influx is practically nil. The kick tolerance formulae yield higher results with increasing wellbore inclination and will mathematically indicate an infinite kick tolerance at 90 degrees. These two statements hold true provided that the gas kick remains in the horizontal section of the wellbore.

In general terms, this indicates that horizontal wells have a greater ability or tolerance to safely take a kick without fracturing the weakest formation at the moment of well closure. However, coupled with this increased kick tolerance, there is the potential for a much greater influx volume which could potentially result in a scenario which is worse for the well kill.

4 WELLBORE FLUID PRESSURE GRADIENTS

4.1 EQUIVALENT MUD WEIGHT (EMW)

The most convenient method of describing down hole pressure is in terms of an equivalent mud weight, EMW (ppg, kg/m^3, kg/l).

EMW is used in order that down-hole pressure can easily be related to the density of a mud column. EMW can therefore be used to describe a formation pressure as well as a pressure applied by a column of mud.

The hydrostatic pressure of the mud column acts as a result of the height of fluid between the flowline and the point of interest in the wellbore. The EMW must therefore be referenced to the flowline.

It is important that the effect of flowline elevation be taken into account when describing formation pressure in terms of an equivalent mud weight because formation pressure is often referenced to sea level.

4.2 EQUIVALENT CIRCULATING DENSITY (ECD)

When a well is being circulated, back pressure created by the passage of the mud up the annulus exerts an additional pressure at any point along the annulus. These annular pressure losses (APL's) can be quantified and when added to the hydrostatic pressure exerted by the mud can be expressed as a mud weight or ECD (ppg, kg/ m^3, kg/l).

The main factors affecting ECD are:

- Hole depth
- Hole size
- Hole condition (e.g. balling, packing off, etc)
- (External) drillstring geometry
- Circulation rate

- Pipe rotation
- Mud weight
- Mud rheology
- Quantity of drilled cuttings in the annulus

4.3 EQUIVALENT STATIC DENSITY (ESD)

At elevated pressures and temperatures the hydrostatic pressure exerted by a static column of mud at the bottom of the hole cannot be calculated directly from the mud weight measured on surface. This is due to a combination of fluid compressibility and thermal expansion and results in a greater bottom hole pressure than expected.

For example, in a 16,500 ft TVD (5037m) well with a mud weight of 18.1 ppg (2170 kg/ m3, 2.17 kg/l) and a surface mud temperature of 122°F (50°C), the static bottom hole pressure was measured downhole. This value was 0.16 ppg (20 kg / m^3, 0.02 kg/l) above the value calculated from the surface mud weight. Therefore, for certain wells, it is essential that mud weights be corrected for the effect of bottom hole temperature.

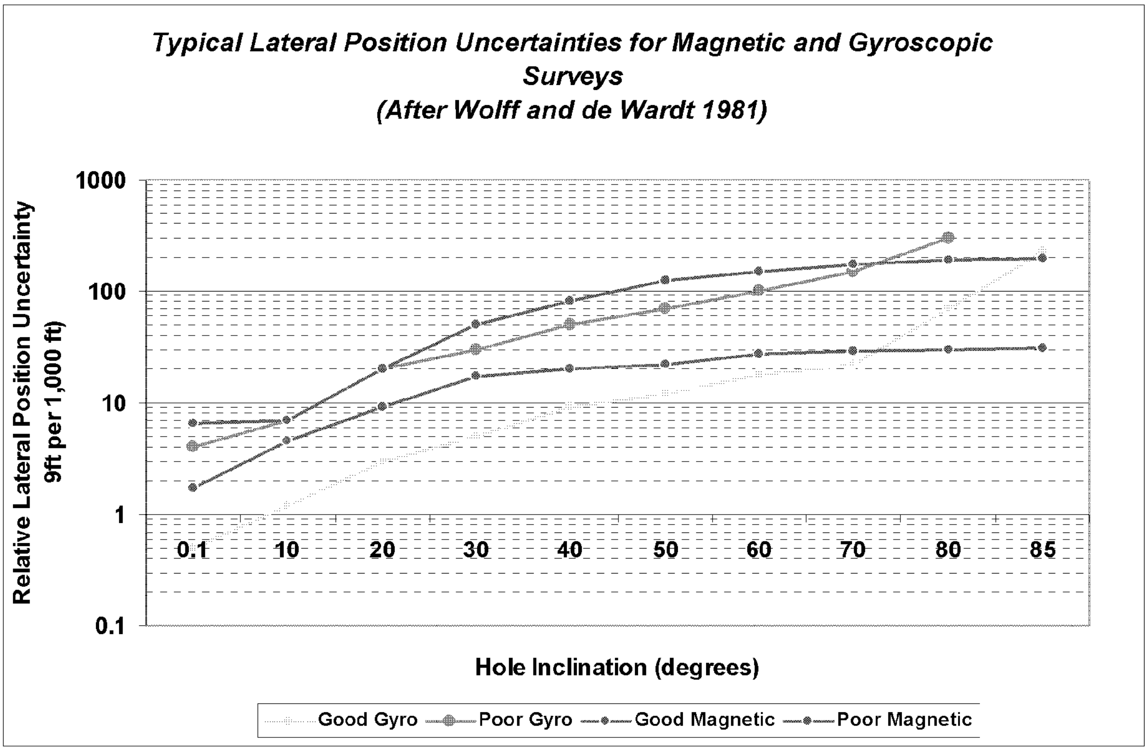
5 COLLISION AVOIDANCE

Collision avoidance is particularly important in the shallow sections of platform or subsea template wells, generally down to the surface casing depth. Accurate surveys over this section of hole being drilled, and all wells in close proximity, may reduce the requirement for shutting in producing wells during close proximity drilling.

Survey uncertainty in this hole section should be kept to less than 2 ft/1000 ft. Figure 2.4.1 below gives typical surveying tool accuracy. The anti-collision criteria should be clearly stated with the appropriate survey program and the required safety factors in the drilling program. If the well being drilled is within the “no go” area of another well, then drilling must be suspended until that well has been plugged below the prognosed depth of interception.

While drilling in close proximity to other wells, returns must be monitored for metal cuttings. If metal cuttings are detected, drilling should stop immediately. A survey shall then be run to determine the position of the wellbore.

Figure 2.4.1, Typical Lateral Position Uncertainties for Magnetic and Gyroscopic Surveys



1 DEFINITION

Primary well control is the use of wellbore fluid density to provide sufficient hydrostatic pressure to prevent the influx of formation fluid (i.e. a kick) into the wellbore. It is of the utmost importance that primary control is maintained at all times by:

- Using drilling and completion fluids of an adequate density.
- Keeping the well full of an adequate density fluid at all times.
- Continuously monitoring active pit volumes, especially during tripping.
- Immediately detecting changes in the density, volumes and flow rate of drilling fluids from the wellbore and taking the appropriate action.

2 CAUSES OF KICKS

There are 5 major causes for the loss of primary well control.

2.1 FAILURE TO FILL THE HOLE PROPERLY WHILE TRIPPING

As the drillstring is pulled from the hole, the mud level drops due to the volume of pipe being removed. As the mud level drops the hydrostatic pressure may be reduced enough to lose primary well control allowing formation fluids to enter the wellbore.

2.2 SWABBING

The hydrostatic pressure in the wellbore will always be reduced to some extent when the drillstring or any downhole tools are being pulled from the hole. The reduction in hydrostatic pressure should not be such that primary control is lost.

Swabbing is caused by one or more of the following:

- High pulling speeds.
- Mud properties with high viscosity and high gels.
- Tight annulus (BHA/hole clearance) or restricted annulus clearance.
- Mud density in use is close to formation pressure.

2.3 LOST CIRCULATION (REFER TO SECTION 8 SUBSECTION 8)

When lost circulation occurs, the drilling fluid level can drop and a reduction in hydrostatic pressure in the wellbore may cause the loss of primary well control. Loss of circulation may result from one or more of the following:

- Cavernous or vugular formations.
- Naturally fractured, pressure depleted or sub-normally pressured zones.
- Fractures induced by excessive pipe running speeds, especially if the mud density is close to the fracture gradient.
- A restricted annulus due to balling of BHA or sloughing shales/mobile formations.
- Excessively high annular friction losses.
- Excessive pressures caused by breaking circulation when mud gel strength is high.
- Mechanical failure (casing, riser, etc).

2.4 INSUFFICIENT MUD WEIGHT

When the hydrostatic pressure due to drilling fluid density is less than formation pressure of a permeable zone, formation fluids will enter the wellbore. This may occur due to the following:

- Drilling into an abnormal pressure zone.
- Dilution of the drilling fluid on surface (reduction in MW).
- Reduction in drilling fluid density due to influx of formation fluids, in particular gas (refer to Section 4 Subsection 4, Heading 4, "Gas Cut Mud").
- Settling of weighted material (barite sag).
- Failure to displace riser to kill mud after circulating out a kick.
- Pumping long columns of lower weight fluids during specific operations (e.g. hole cleaning pills in inclined sections, spacers during cementing, etc).
- After cementing and while WOC the hydrostatic pressure of the slurry may be reduced to the equivalent of the mixwater as it starts to set.

2.5 LOSS OF RISER DRILLING FLUID COLUMN

On floating rig operations, the loss of the drilling fluid column in the riser may result in a reduction of hydrostatic pressure in the wellbore and may cause the loss of primary well control.

This loss of riser hydrostatic column could be due to:

- Accidental disconnect.
- Riser damage.
- Displacement of riser with seawater or a lower density fluid.
- Accidental "U-tubing" into choke/kill lines.

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1 DEFINITION

Secondary well control is the proper use of blowout prevention equipment to control the well in the event that primary control cannot be properly maintained.

Early recognition of the warning signals and rapid shut-in are the key to effective well control. By taking action quickly, the amount of formation fluid that enters the wellbore is minimized.

2 KICK SIZE AND SEVERITY

Minimizing kick size is fundamental in enhancing the safety of a well control operation. Smaller kicks provide lower choke or annulus pressure both upon initial closure and later when the kick is circulated to the choke. The kick size is dependent on a number of parameters, all of which are related to well productivity but only some of which we can influence. These can be summarized:

2.1 CONTROLLABLE PARAMETERS

Parameter	Influence
Degree of underbalance (drawdown on the reservoir)	Mud weight
Length of reservoir exposed	ROP + kick detection time
Length of time well remains underbalanced	Kick detection and shut in time
Wellbore diameter	Hole size

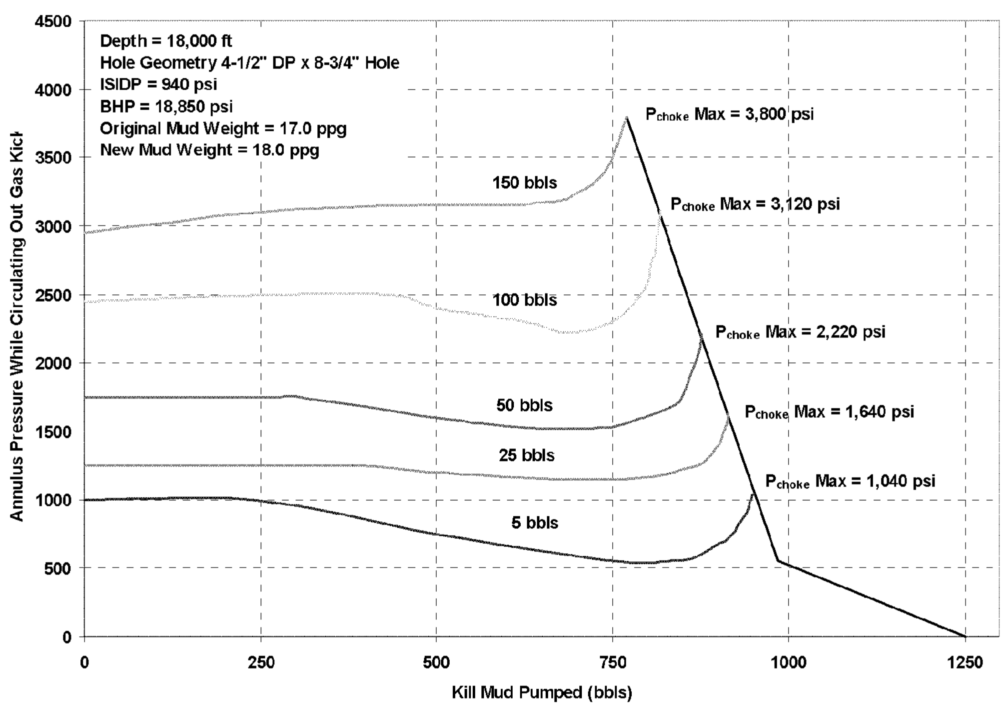
2.2 NON-CONTROLLABLE PARAMETERS

- Formation permeability.
- Formation fluid type/mobility.
- Wellbore skin (can be controlled to a certain extent).

It is important to understand and focus on the 4 ‘controllable parameters’ during well planning and operations.

Figure 3.2.1 shows the importance of rapid shut-in to reduce influx volume.

Figure 3.2.1, Effects of Influx Volume on SICP (Surface BOP)



1 DEFINITION

In the event that secondary control cannot be properly maintained due to hole conditions or equipment failure, certain emergency procedures can be implemented to prevent the total loss of control. These procedures are referred to as "Tertiary Well Control" and usually lead to partial or complete abandonment of the well.

The procedures to be applied depend on the particular operating conditions encountered, and specific recommendations regarding appropriate tertiary control procedures cannot be given until the circumstances leading to the loss of secondary control have been established.

However, there are three procedures that are widely used. These involve the use of:

- Diesel-Bentonite 'gunk' plugs
- Barite plugs
- Cement plugs

2 PROCEDURES

2.1 DIESEL-BENTONITE 'GUNK' PLUGS

A diesel-bentonite plug is a slurry of bentonite mixed in diesel oil which is pumpable at surface and develops a high shear strength when displaced into position downhole. Cement or LCM can be added to the slurry if necessary.

2.1.1 KEY FEATURES

- Designed to set upon contact with a water-based mud or formation water if squeezed into the formation.
- The bentonite hydrates rapidly upon contact with water to form a gelatinous plug with the consistency of putty.
- If cement is included in the slurry it will increase the rigidity of the plug when set and provide a higher compressive strength.
- It is preferable to spot the plug through open-ended drillpipe or a slotted, closed-ended mule shoe.

2.1.2 ADVANTAGES

- It can be pumped through the bit and the drillstring recovered.
- The material required is normally available at the rig site.
- The plug can be drilled easily.

2.1.3 DISADVANTAGES

- Any contact with water before the plug has been displaced will cause it to 'flash' set.
- The plug will degrade over time and therefore the problem formation will have to be cemented or cased at the first opportunity.

2.2 BARITE PLUGS

A barite plug is a slurry of barite in fresh water or diesel oil which is spotted in the hole to form a barite bridge that will seal the well and allow control to be re-established.

2.2.1 KEY FEATURES

- The plug is displaced through the drillstring and, if conditions allow, the string is pulled up to a safe point above the plug.
- The barite settles out rapidly to form an impermeable mass capable of shutting off high rates of flow.
- The effectiveness of a barite plug derives from the high density and fine particle size of the barite and its ability to form a tough impermeable barrier.
- A minimum final plug length of 200 ft (60 m) and not less than 10 bbls (1.5m3) volume is recommended to ensure a good seal.

2.2.2 ADVANTAGES

- It can be pumped through the bit and offers a reasonable chance of recovering the drillstring.
- The material required is normally available at the rig site.
- The plug can be drilled easily if required.

2.2.3 DISADVANTAGES

- The risk of the barite settling out and the consequent plugging of the drillstring if pumping is stopped before the slurry has been completely displaced.

Refer to Section 7.2, Heading 5.1.4 Kill Methods, for recipes in WBM and OBM.

2.3 CEMENT PLUGS

A cement plug can be used to shut off a downhole flow. However, this generally involves abandonment of the well and loss of most of the drilling tools.

2.3.1 KEY FEATURES

- Cement plugs are set by pumping a quantity of quick setting (accelerated) cement into the annulus via the drillstring.
- The cement is usually displaced until the pump and choke pressures indicate that a bridge has formed.
- Quick setting cement reduces the possibility of gas cutting.
- If a cement plug has to be set off bottom with mud below it, then consideration should be given to spotting a slug of viscous mud below the zone to be plugged. This precaution should be considered in long or deviated holes or when the cement slurry is substantially heavier than the mud.
- Cement plugging should be regarded as the final option.

2.3.2 ADVANTAGES

- Highest chance of success in bridging/sealing troublesome formation.
- Materials required are normally at rig site.

2.3.3 DISADVANTAGES

- Little chance of recovering drillstring.
- Subsequent drilling will require a sidetrack if fish left in hole.
- Possible plugging of drillstring during cement placement precluding a second attempt.

3 BLOWOUT/UNDERGROUND BLOWOUT

It is critical to establish, prior to drilling any hydrocarbon bearing formations, that potential blowout/underground blowout situations have been addressed. This must be covered in the Emergency Response Procedures developed jointly by the Company and the Operator.

Refer to Section 7.2, Heading 5 Blowout / Underground Blowout for additional information about blowouts/underground blowouts.

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1 MUD PIT MANAGEMENT

1.1 DURING NORMAL OPERATIONS

Use the minimum amount of solids control pits while still being able to use the degasser pit(s).

Keep the surface area of the active mud system as small as possible to improve kick detection. Reserve mud pits must be isolated from the active system.

Ensure all pit volume measurement systems are calibrated and pit isolation valves are sealing properly before drilling into possible hydrocarbon bearing zones.

Keep all mud treatment and pit transfers to the absolute minimum during critical sections of the well. The Mud Engineer and Derrickman must keep the Driller and Mud Loggers informed of any transfers or treatment of mud.

1.2 DURING WELL CONTROL OPERATIONS

The following checklist should be considered prior to circulating out a kick to ensure correct surface arrangement of pits.

Check:

- Method used to kill the well.
- Useable pit volume in relation to the hole volume.
- Available pit capacity to accommodate the gain caused by kick expansion during displacement.
- Method of weighting up the mud.
- The type and toxicity of the kick.
- Method of disposal of the kick at surface.
- Treatment of contaminated returns.

2 BULK AND CHEMICAL STOCKS

The management of bulk materials and related chemical inventory must take into account all operational requirements, including the suspension or abandonment of the well. Rig stock levels must not fall below the minimum quantities stated below, at any time, prior to the completion of all well operations.

Barite and Mud Chemical Stocks:

The minimum quantity of barite (or any alternative weighting material) held on board must be sufficient to raise the density of the mud system by at least 1 ppg (120 kg/m^3, 0.12 kg/l) where,

- **Mud system = Hole volume (no pipe) + 150 bbls (24 m^3) surface volume.**

The minimum stocks of mud chemicals held on board must be sufficient to enable the mud system (as defined above) to be weighted up by at least 1 ppg (120 kg/m^3, 0.12 kg/l).

Cement and Cement Chemical Stocks:

The minimum quantities of bulk cement and cement additives held on board must be sufficient to set at least two (2) 500 ft (150 m) cement plugs in the hole section being drilled.

LCM Materials

The minimum required quantities of LCM materials held on board must be specified in the drilling program.

Drilling operations must be stopped if minimum stock levels are reached.

3 INSTRUMENTATION

3.1 PRESSURE MEASUREMENT

The rig must be equipped to read standpipe and annulus pressures. These gauges are fitted to the Driller's console and the remote choke operating panel and must be rated to display pressures equal to the working pressure of the equipment.

Standpipe and choke/kill lines must all have at least two (2) separate gauges reading the same pressure for the purposes of redundancy and calibration. These should be cross-checked during every BOP test.

A set of choke, standpipe and kill line gauges must be visible at the remote choke operating panel in the Driller's station and from the manual/adjustable choke on the choke manifold.

It must be possible to install (and remove) low pressure gauges on the choke and kill manifold(s) and on the remote choke operating panel.

Hydraulic fluid and a hand charge pump must be available on the drill floor.

3.2 FLUID VOLUME MEASUREMENT

A pit level monitoring system, capable of registering gains and losses and displaying the contents as a volume, must be installed in all the active mud pits.

A gauge/readout complete with an adjustable, audio-visual alarm must be installed on the Driller's instrument panel and must be able to monitor the pit volume(s) separately or collectively.

During well control operations it may be necessary to bleed volumes from the well as small as 1/2 bbl. (0.08 m^3) and the trip/stripping tank gauges (electronic and mechanical) must be able to display this increment.

3.3 RETURN FLOW MEASUREMENT

The flowline must be equipped with a device for measuring the rate of return flow from the well.

A gauge/readout complete with an adjustable, audio-visual alarm must be installed on the Driller's instrument panel.

3.4 PUMP OUTPUT

Gauges and counters must be available (at both the Driller's station and the remote choke operating panel) to show the following:

- Pump strokes per minute.
- Cumulative pump strokes.

4 EQUIPMENT LINE UP FOR SHUT-IN

4.1 DIVERTER

The Driller is responsible and accountable for ensuring the diverter and overboard line valves are in the correct setting at the beginning of each tour.

- The diverter insert packer must always be in and locked down after the riser is run (except during the handling of BHA's).

4.2 CHOKE AND KILL MANIFOLD

The Driller is responsible and accountable for ensuring the correct manifold lineup is checked at the beginning of each tour.

- The choke and the valve(s) immediately upstream of chokes on the choke manifold are to be kept in the closed position. If the valve downstream of the choke is of same pressure rating as the manifold upstream, then this may be closed instead.
- Choke and Kill manifold valves must be lined up to obtain immediate pressure readings after well is shut-in.
- Choke and Kill manifold low-pressure valves must be lined up to direct the flow of the well through the mud gas separator (MGS).

4.3 BOP VALVES

- Remote operated choke line valve (HCR) on surface BOP's or failsafe valves on subsea BOP's are to be kept in closed position.

1 INTRODUCTION

During relevant operations, Well Control Drills must be held on at least a weekly basis with each crew or more often if the Senior Toolpusher considers it necessary. The type of drill should be routinely alternated (operations permitting) to improve the crews' familiarization.

Well control drills must be conducted under the supervision of the Senior Toolpusher or his designee and must be structured to acquaint each crewmember with his role during a well control incident so that he can perform it promptly and efficiently. Well control drills should be initiated at unscheduled times when operations and hole conditions permit.

A well control drill plan, applicable to the particular Installation, must be prepared for each crewmember outlining the assignments he is to fulfill during the drill and establishing a prescribed time for the completion of each stage of the drill.

The interface between the drill crews and the mud logging personnel must be considered when planning the well control drills. Situations may arise where mud logging personnel are first to be aware of potential kick indicators. Where applicable, the mud logging personnel and the planned method of communication with the drill crews must be included in the drills.

A copy of the complete well control drill plan must be posted.

The timing of the drills should be selected so that crews can practice drills while on bottom and while tripping.

The following must be recorded in the IADC report:

- Type of drill.
- Reaction time from the moment the kick is simulated until the designated crewmember is ready to start the shutting-in procedure.
- Total time taken to complete the drill.

2 DIVERTER DRILL

When the posted instruction is to divert, a diverter drill must be held by each crew at the beginning of every tour.

Drills are particularly important in familiarizing all personnel with the proper and immediate actions to take, since there is little time to react during an actual emergency. The actions taken by the Driller and his crew must be planned and practiced.

Diverter drills must be carried out to improve the crew's reaction time and prove the operation of all diverter system equipment. A drill must be carried out before drilling out the surface casing.

A specific detailed diverter drill must be prepared for each rig/well that should include the following:

- Simulation of diverting the well according to diverter procedures (includes lining up pumps to heavy mud).
- The sending of essential personnel to their pre-assigned positions.
- The sending of all non-essential personnel to the muster point or assigned position as per the Emergency Response Plan.
- Simulate "get ready for disconnect and move off location" on floating rigs.

3 KICK WHILE TRIPPING (TRIP DRILL)

This drill must only be conducted if the BHA is inside casing (but not in or above the BOP's).

The Driller and crew should complete the following steps to secure the well:

- The Driller should recognize the indication of a kick and alert the crew.
- Lower the drillstring and set the slips. Install a safety valve in the open position. Close the safety valve.
- Simulate shutting-in the well using the Annular Preventer (Upper Annular preferred in the case of subsea BOP's where outlet is installed to remove gas trapped in the BOP).
- Simulate opening the HCR/'fail-safe' valves on the choke line at the BOP's.
- Make up the kick assembly or the topdrive/kelly to the string and open the safety valve.
- Pick up to the pre-determined space-out position for the Annular Preventer.
- Open and adjust the compensator to mid-stroke (on floating rigs).
- Read and record the SIDPP and SICP.
- Measure the gain in the active mud pit.
- Prepare to strip pipe, including lining up equipment as required and assigning individual responsibilities, and preparing stripping worksheets and instructions.

4 KICK WHILE DRILLING (KICK DRILL)

This drill may be conducted either in an open or cased hole. If the drill is conducted when in open hole the well must not be shut-in and pipe rotation must be maintained.

The Driller and crew must complete the following tasks to secure the well:

- Recognize the kick and alert the crew.
- Pick up off bottom.
- Stop the pump(s).
- Flow check. If the trip tank can be lined up quickly (i.e. remotely), check the well for flow on the trip tank with the trip tank circulating.
- Simulate shutting in the well using the Annular Preventer. **Do not** shut the well in if in open hole.
- Simulate opening the HCR / 'fail-safe' valves in the choke line at the BOP stack.
- Simulate setting the DSC at mid stroke (floating rigs).
- Take readings of the shut-in casing and drillpipe pressures (SICP, SIDPP).
- Measure the gain in the active tanks (confirm with the mud logging unit).
- Double check the space-out is correct, simulate hanging off the pipe and close and lock the hang-off rams (on floating rigs).
- Check all valves on choke manifold and BOP stack for correct position.
- Simulate stopping all hot work.

This operation must be performed at least once per week (well conditions permitting) with each crew.

5 WELL KILL DRILL (CHOKE DRILL)

Before drilling out the shoe of casing set above the reservoir or a high-pressure zone, a drill including actual closure of BOP's, circulation through chokes, mustering of crews, pressuring of silos etc. must be conducted. In particular, this will give the choke operator a "feel" of the choke operation and pressure lag times in the well. For floating rig operations, this drill could include hanging off the pipe.

6 STRIPPING DRILL

Strip drills must be held by each drill crew at least once per year. The preferred timing in a well for a stripping drill is when inside the intermediate and/or production casing before drilling out the shoe-track. In exceptional circumstances alternative times in the well may be selected to conduct the drill to suit operations and well conditions. *(Refer to Section 10 Subsection 2.2 for forms.).*

1 MAXIMUM ALLOWABLE ANNULAR SURFACE PRESSURE (MAASP)

MAASP is defined as the surface pressure which, when added to the hydrostatic pressure of the existing mud column, results in formation breakdown at the weakest point in the well.

This value is normally based on LOT data, with the assumption that the formation at the shoe is the weakest point in the open hole section. This assumption should be reconsidered if losses to the formation are sustained or weaker zones are encountered in subsequent drilling. Conversely, the calculated value of MAASP can be conservative and if exceeded, may not result in formation breakdown for the following reasons:

- MAASP has been calculated from readings obtained from a LOT (refer to Section 2 Subsection 3).
- Drilling fluid properties may have changed since the LOT was conducted.
- The deposition of filter cake and the effect of temperature as drilling proceeds may improve the effective formation strength.
- The near-wellbore region may be weaker than the surrounding formation.

During well control operations, it is most important that the position of the kick, in relation to the last casing shoe, is monitored so that the MAASP figure can be used correctly.

1.1 CALCULATION OF MAASP

When the hydrostatic head of the mud in the hole changes, the value of MAASP must be recalculated.

$$\text{MAASP (psi)} = [\text{EMW}_{\text{LOT}}\text{ (ppg)} - \text{MW (ppg)}] \times 0.052 \times \text{TVD}_{\text{shoe}}\text{ (ft)}$$

$$\text{MAASP (kPa)} = [\text{EMW}_{\text{LOT}}\text{ (kg/m}^3\text{)} - \text{MW (kg/ m}^3\text{)}] \div 102 \times \text{TVD}_{\text{shoe}}\text{ (m)}$$

$$\text{MAASP (bar)} = [\text{EMW}_{\text{LOT}}\text{ (kg/l)} - \text{MW (kg/l)}] \times 0.0981 \times \text{TVD}_{\text{shoe}}\text{ (m)}$$

Automatic MAASP control devices must be disabled.

2 SLOW CIRCULATING RATES (SCR)

Well control operations are conducted at reduced circulating rates in order to:

- Minimize annulus pressures.
- Allow for more controlled choke adjustments.
- Allow for the weighting up and degassing of the mud and disposal of the influx.
- Reduce the chance of choke erosion.
- Reduce risk of overpressuring system if plugging occurs.

Slow circulating rate pressures for each pump must be taken:

- If practical, at the beginning of every tour.
- Any time the mud properties are changed.
- Any time the bit nozzle configuration or bottom hole assembly is changed.
- As soon as possible after bottoms-up from any trip.
- At least every 1000 ft (305 m) of new hole. This must be reduced to at least every 500 ft (150 m) in known hydrocarbon bearing hole sections.
- After MAJOR mud pump or surface equipment changes/repairs.

A minimum of two circulating rates must be obtained for all pumps. When determining slow circulation rates, consider wellbore geometry, water depth, choke line lengths and equipment limitations.

If a kill assembly and/or the cement unit are planned to be used for well kill operations, SCR's should be taken using this equipment.

The pressures must be recorded using the gauge that will be used during well kill operations.

The SCR pressures and corresponding pump rates must be recorded on the IADC report and on the Daily Drilling Report.

3 CHOKE LINE FRICTION LOSSES (CLFL)

Choke line pressure losses at Slow Circulation Rates should be taken:

- Before drilling out first casing string after BOP installation.
- After any significant change in mud weight or other mud properties.

It is important that the CLFL is known for a wide range of circulating rates. From this information the additional pressure on the well can be assessed at a range of displacement rates and the most suitable circulating rate chosen (refer to Section 10 Subsection 8, Choke Line Friction Losses, CLFL).

3.1 PROCEDURES FOR RECORDING CLFL

There are four recognized methods of recording CLFL at SCR's of 1 - 5bbls/min (0.16-0.8 m^3/min).

1. Take the difference between the drillpipe pressure required to circulate the well through a full open choke with the BOP closed and the drillpipe pressure required to circulate the well through the marine riser with the BOP open.
2. Circulate the well through a full open choke with the BOP closed and recording the pressure on the (static) kill line. The kill line pressure will reflect the choke line pressure loss.
3. Circulate down the choke line and up the marine riser with the BOP open. The pressure required for circulation is a direct reflection of the choke line pressure loss.
4. Circulate down the kill line taking returns through a full open choke with the wellbore and riser isolated by closing the BOP's. Pressure observed is double the choke line pressure loss.

The pressure readings provided by the choke manifold pressure sensor, rather than the pump pressure gauge, must be recorded since the effect of the pressure losses between the pump and the choke manifold are eliminated.

Whenever the choke/kill line is used to calculate pressures the correct fluid density must be confirmed.

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1 TRIPPING PRACTICES

The majority of kicks are taken while pulling the drillstring from the wellbore. This is a problem that can be avoided if the crew is well trained and if proper procedures are followed.

During tripping the potential exists for a significant reduction in bottom hole pressure due to the following effects:

- **Swab pressures due to pipe motion.**
- **Reduction in height of the mud column as pipe is removed from the well.**

1.1 BEFORE TRIPPING

1.1.1 TRIP MARGIN

To minimize the risk of taking a kick when tripping out of hole, a sufficient mud weight must be in use which gives an overbalance on the formation. This increment in mud weight is called the "Trip Margin" and can be a selected value (e.g. 200 psi (1400 kPa, 14 bar)) or calculated (refer to Section 10 Subsection 4.2).

In cases where trip margin can only be a very small increment, consideration should be given to pumping out of hole.

1.1.2 CIRCULATION

The mud must be conditioned to minimize excessive swab/surge pressures when tripping.

Any entrained gas or cuttings should be circulated out.

It is permissible to trip with stable 'seepage' losses (i.e. less than 20 bbls/hr or 3.2 m^3/hr). If losses are in excess of this, authorization from the Operations Manager Performance is required.

The difference between the mud weight 'in' and 'out' of the well must be uniform.

1.1.3 DETERMINE THE MAXIMUM PIPE SPEED

Swab/surge pressures should be calculated for various tripping speeds. If software is not available on the rig then tools can be found on the intranet that could provide some indicative numbers.
http://www.rigcentral.com/hqs/pt/well_operations_group/well_control1.asp

1.1.4 LINE UP THE TRIP TANK

The trip tank must be filled with adequate weight fluid and function tested prior to removing the topdrive or kelly.

A trip sheet must be prepared. The trip sheet will show the expected hole fill volumes as the drillpipe is pulled out of the hole. As the trip out of the hole proceeds, the actual hole fill volumes must be recorded.

The Mud Loggers must independently monitor the mud volumes during the trip. They must notify the Driller if any discrepancies occur during the trip. If any discrepancies cannot be resolved, the Senior Toolpusher must be informed.

Should the trip tank pump fail, an alternative will be to use a mud pump while pulling pipe. The annulus must be filled with mud before the change in mud level decreases the hydrostatic pressure by 75 psi (500 kPa, 5 bar) or every 5 stands of drillpipe, whichever gives a lower decrease in hydrostatic pressure. When pulling HWDP or drill collars the hole must be filled every stand. The pit from which the hole is being filled must be isolated from all other pits and the volume closely monitored.

1.1.5 DRILL FLOOR PREPARATION - SAFETY VALVES

Suitable safety valves made up with the appropriate XO subs to fit all drillpipe and BHA connections must be on the drill floor in an accessible place and always in the "open" position. The closing/opening wrench must be readily available for immediate use and there must be correct means of lifting.

An IBOP valve must be kept on the drill floor should it become necessary to strip into the hole.

1.2 PULLING OUT OF HOLE (POOH)

If the trip margin is insufficient/unknown, conduct a short check trip. Once back on bottom, the ability to safely trip can be assessed from the level of the trip gas following a bottoms-up circulation.

Pulling wet pipe should be avoided if possible. If hole problems are expected, tripping through the problem intervals before pumping a slug should be considered.

1.2.1 SLUGS

The following calculations must be made (refer to Section 10 Subsection 4):

- **Volume of slug required for the desired length of dry pipe.**
- **The gain in returned volume produced by the U-tubing of the slug.**

Where possible, rotate the pipe while pumping and allow the slug to equalize.

Allow the trip tank level to stabilize before POOH.

The Toolpusher on tour must be on the drill floor to observe the first 10 stands of every trip or until the bit is inside the casing shoe.

The trip tank must be closely monitored at this stage to ensure that swabbing is quickly detected.

Circulating the hole across the trip tank will continuously monitor the pipe displacement.

If the hole is taking the proper amount of fluid and if there is no drag or overpull that could generate swabbing, then the pipe wiper must be installed after pulling the first 5 stands or after the bit is pulled into cased hole.

Whenever a trip is interrupted, a full opening safety valve must be installed and the well monitored on the trip tank.

Tripping must be stopped whenever the trip tank is refilled. The lower and upper tank fill figures must be checked with the Mud Loggers before proceeding with the tripping operation.

1.3 NO PIPE IN THE HOLE

The trip tank must be lined up and used to monitor hole conditions while the drillstring is out of the hole. A person must be assigned to monitor the trip tank.

1.4 RUNNING IN HOLE (RIH)

There are 2 main issues when RIH:

- **Surge pressures developed while RIH can cause formation breakdown leading to losses.**
- **An undetected kick could exist in the well which is "run into" when tripping in.**

1.4.1 RUNNING SPEED

The speed at which the drillstring is run in the hole must be controlled to reduce the surge effects on the hole. Surge calculations should be made and the appropriate schedule given to the Driller.

1.4.2 BREAKING CIRCULATION

To reduce possibilities of high surge pressures, consider breaking circulation before entering the open hole. Once circulation is broken, conduct a flow check before continuing RIH. On bottom, slow pipe rotation should be considered to break mud gels prior to breaking circulation.

1.4.3 FILLING DRILLPIPE

With a float in the string, drillpipe must be filled at predetermined intervals. This interval should not exceed 3,000ft and if practical should be timed to coincide with emptying of the trip tank. When the BHA is in open hole, the drillstring should be reciprocated while filling to prevent becoming stuck.

The selected interval, or number of stands run before filling, must take into consideration the following factors:

- **The loss in hydrostatic due to a float failure must not result in an underbalanced situation**
- **Tubular collapse pressure ratings must never be exceeded**
- **A ported float may allow an influx into the drillstring in the event of a kick**
- **A ported float may affect displacement volumes as the volume of fluid passing through the float could be considerable depending on the pressure differential and time between filling**
- **Too much differential pressure could potentially plug bit nozzles or BHA components below a ported float**

- **Large amounts of air could become trapped and subsequently displaced into the annulus**
- **Differential pressure limitations (if any) of logging tools (LWD/MWD) must not be exceeded**
- **The string should be filled prior to entering any known hydrocarbon bearing or problematic**

1.4.4 MUD PIT/TRIP TANK

The trip tank or a mud pit must be monitored while tripping into the hole. Tripping must be stopped whenever the trip tank is emptied. The lower and upper tank fill figures must be checked with the Mud Loggers before proceeding with the tripping operation.

1.4.5 INCORRECT HOLE FILL

If at any time during the tripping operation the hole is not taking the proper amount of drilling fluid (or if the hole is giving fluid), stop and install the full opening safety valve, flow check the well and inform the Toolpusher.

If the hole is taking too much fluid this may be due to a high tripping speed or gelled up mud. Reduce tripping speed and/or break circulation.

1.4.6 BOTTOMS-UP CIRCULATION

During the first circulation of bottoms-up after a round trip, drilling fluids should not be transferred from the reserve to the active system.

1.5 FLOW CHECKS

A flow check is the observation of the well without circulation. Flow checks are made to determine if the well is or is not flowing.

The duration of a flow check may be specified by the Senior Toolpusher but must take whatever time is necessary to determine whether the well is static.

1.5.1 FLOW CHECKS DURING A TRIP

Flow checks must be performed at the following times:

- **At the bottom of the well before any trip out of the hole.**
- **At the lowest casing shoe.**

- **Anytime the hole displacement is incorrect during a trip.**
- **Anytime the Driller (or the person performing the Driller's function) has any concerns regarding the well status.**
- **If continuous volume monitoring of the hole volume is not possible, then a flow check must be made, prior to pulling the HWDP or Drill Collars through the BOP's.**
- **Anytime a trip is suspended in order to boost the riser.**
- **Prior to recommencing a trip after boosting the riser.**

1.5.2 FLOW CHECKS DURING OTHER WELL OPERATIONS

Flow checks must be performed at the following times:

- **While making a connection during drilling operations.**
- **After a drilling break. (Positive or Negative).**
- **After unseating a packer.**
- **After unseating a seal assembly.**
- **After cutting a casing string.**
- **Before and during hanging off the blocks for slipping and cutting drilling line.**
- **While testing the BOP.**
- **During wireline operations.**
- **Before and while running a survey.**
- **After any well control operation.**
- **At any time the Driller has a doubt about the stability of the well.**
- **Prior to commencing tripping or pumping out of hole while boosting the riser.**

2 DRILLING WITH OBM

2.1 KICK DETECTION

Kicks taken while drilling with OBM may be difficult to detect due to the problems created by gas solubility in OBM. Gas may go into solution during a kick instead of staying as a discrete phase as occurs with WBM.

When the gas saturated mud reaches a depth where pressure/temperature are at the bubble point, the gas will start coming out of solution causing a very rapid increase in well flow. In some cases this can unload the annulus resulting in large pit gains and high annulus shut-in pressures.

Gas solubility increases as:

- **Bottom hole pressure increases.**
- **Gas density increases.**
- **Percentage of base oil increases.**
- **Bottom hole temperature decreases.**
- **Solids content, percentage of emulsifiers and/or brine decreases.**

2.2 SPECIAL PRECAUTIONS - WHILE DRILLING

Monitor active pit for small gains (< 5 bbls/0.8m^3).

Be prepared to shut-in or handle increases in pit volume when circulating after drilling breaks.

The Senior Toolpusher or his designee must be notified of any trend changes or flow checks.

Base oil, oil base mud or diesel should not be transferred directly from supply boat to the active mud pits while drilling operations are in progress.

Flow checks taken after any kick indicators have been observed should be extended to between 15 and 30 minutes. Even with a static flow check, consideration should be given to circulating bottoms-up.

If the Driller encounters any kick indicator, then consideration should be given to shutting in the well even if a flow check proves inconclusive. If there is no indication of flow, it does not necessarily mean that a kick has not entered the wellbore. Clear instructions must be given to the Driller for this occurrence prior to start of drilling an OBM section.

Consideration should be given to circulating the last 3000 ft (900 m) of the annulus volume below the BOP's out through an open choke.

2.3 SPECIAL PRECAUTIONS - WHILE TRIPPING

If there are signs of a kick while circulating bottoms-up, consideration should be given to completing the circulation through the choke as per the Driller 's method.

This will distinguish trip gas from a real kick and will determine if an increase in mud weight is required.

3 INDICATIONS OF INCREASING FORMATION PRESSURE

The detection of increasing formation pressure is an essential step in maintaining primary well control. There is no one rule that will pinpoint abnormally pressured zones but many of the following indicators, in order of priority, appear before the formation pressure becomes high enough to cause a kick.

3.1 INCREASE IN DRILLING RATE

When abnormal pressure is encountered, differential pressure and shale density are decreased causing an increase in penetration rate (ROP).

3.2 INCREASE IN GAS TREND

Heading 5 below, describes the various "types" of gases which should be continuously monitored. An increasing trend is a strong indicator that the pore pressure gradient is approaching the mud gradient.

3.3 CHANGE IN CUTTING SIZE AND SHAPE

Cuttings from normally pressured shales are small with rounded edges and are generally flat, while cuttings from abnormally pressured shales often become long and splintery with angular edges. As the differential between the pore pressure and the wellbore pressure is reduced, the cuttings have a tendency to "explode" off bottom. In addition, because of a reduction in differential pressure, fluid in the shale can expand causing cracking and sloughing of the shales into the wellbore. A change in cutting shape will occur along with an increase in the amount of cuttings recovered at the surface and this should indicate that abnormal pressure has been encountered.

3.4 TEMPERATURE MEASUREMENTS

The continuous measurement of the mud temperature at the flowline may suggest a change in temperature gradient that is associated with penetrating an abnormally pressured formation. The temperature gradient in abnormally pressured formations is usually higher than normal. This temperature gradient increase occurs before penetrating the interface and may provide early warning of abnormal pressures.

3.5 INCREASE IN TORQUE AND DRAG

Increases in torque and drag often occur when drilling at balance or underbalance through some shale intervals. This condition can be caused by "heaving" or "sloughing" shales resulting in a build up of cuttings in the annulus and excessive fill on connections and trips. Taken alone, increase in torque and drag is not always a reliable indicator since it may be caused by hydratable shales, change of formation, worn out bit, deviated hole, etc.

3.6 DECREASE IN SHALE DENSITY

Shale density normally increases with depth but decreases as abnormal pressure zones are drilled. The density of the cuttings can be determined at the surface and plotted versus depth. A normal trend line is established and any deviation should (in theory) indicate changes in pore pressure.

3.7 CHANGE IN D-EXPONENT

A normalized drilling rate may be defined as a function of measured drilling rate, bit weight and size, and rotary speed.

Because "d" is an indication of "drillability", a plot of "d" versus depth in shale sections has been used with moderate success in predicting abnormal pressure. Trends of d-exponent normally increase with depth, but in transition zones, values of "d" decrease with lower than expected values. Since the d-exponent indicates the pressure difference between formation pressure and wellbore pressure, changing the mud weight will affect the d-exponent.

It should be remembered that the d-exponent was developed primarily for use in shale type formations drilled with rock bits.

3.8 CHLORIDE TRENDS

The chloride content of the mud filtrate can be monitored both going into and coming out of the hole. A comparison of chloride trends can provide a warning or confirmation signal of increasing pore pressures.

An alternative to measuring chloride content of the filtrate is continuous measurement of the mud resistivity both in and out of the hole. Mud additives and make-up water can affect resistivity and chloride measurements.

4 GAS CUT MUD

A minor influx that is not detected as a pit gain may first be identified at the surface in the returned mud. Formation fluids in the returned mud may indicate that a low volume influx is occurring or has occurred, though no gain has been detected. Therefore, returned mud must be monitored for contamination with formation fluids. Constantly recording the flowline mud density and accurately monitoring gas levels in the returned mud accomplishes this.

Mud which is sufficiently gas cut will cause a reduction in bottom hole pressure (BHP).

The presence of gas cut mud does not indicate that the well is kicking (gas may be entrained in the cuttings). However, the presence of gas cut mud must be treated as an early warning sign of a potential kick.

4.1 INTERPRETING GAS LEVELS

Interpreting gas levels in the mud requires an understanding of the conditions under which the gas has entered the mud. Gas can enter the mud for one or more of the following reasons:

- **Drilling a formation that contains gas even with a suitable overbalance.**
- **Temporary reduction in hydrostatic pressure caused by swabbing.**
- **Pore pressure in a formation greater than the hydrostatic pressure of the mud column.**

5 TYPES OF GASES

5.1 DRILLED GAS

As porous formations containing gas are drilled, a certain quantity of the gas contained in the cuttings will enter the mud. This occurs even when drilling overbalanced.

5.2 BACKGROUND GAS

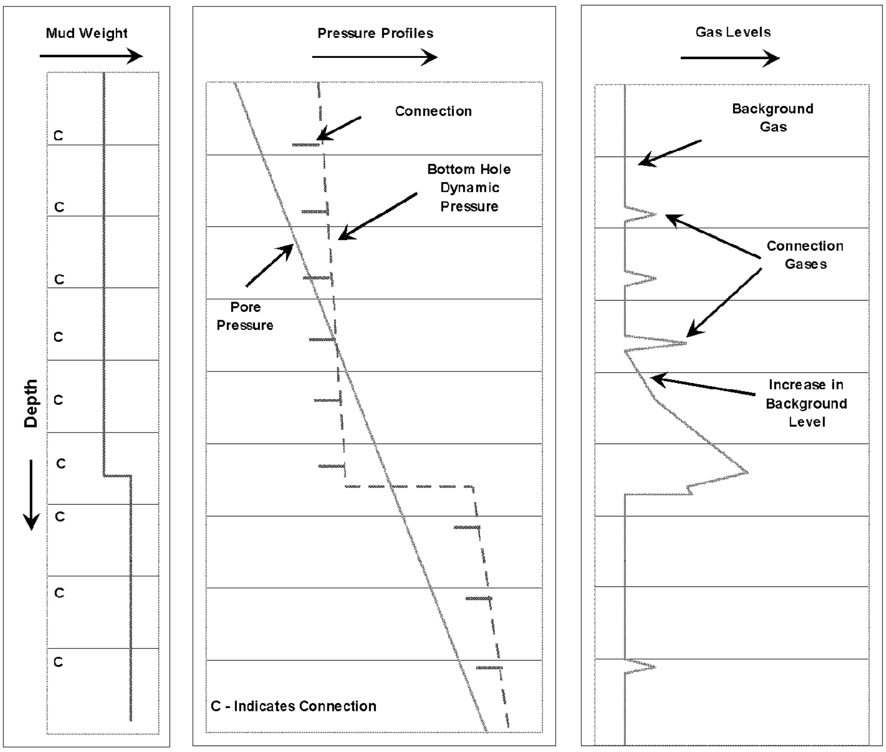
This is the average gas level (excluding peaks) and corresponds to the gas that enters the wellbore under dynamic (circulating) conditions.

5.3 CONNECTION GAS

This is the gas that enters the wellbore under static (non circulating) conditions such as the time when connections are being made.

Connection gas is characterized by peaks of gas that match the time between connections and an increasing trend indicates a potential future kick (refer to Figure 4.4.1).

Figure 4.4.1, Mud Gas Levels as an Indicator of Formation Pressure



If connection gas is present and the ROP is high, limiting the volume of connection gas in the annulus by controlling the drilling rate should be considered.

5.4 TRIP GAS

Trip gas is any gas that enters the mud while the pipe is tripped (or partially tripped) and will be detected in the mud on circulating bottoms-up. If the static mud column is sufficient to balance the formation pressure, swabbing or osmosis may have caused the trip gas from the gas bearing formation to enter the wellbore.

5.5 RE-CIRCULATED GAS

Recirculated gas is gas that is not removed by surface equipment, and is re-circulated into the wellbore, and may be detected when circulated back to surface again.

5.6 SWABBED GAS

This is gas that is introduced into the wellbore when the hydrostatic bottom hole pressure is temporarily less than the gas bearing formation pore pressure at the point of interest. The temporary reduction in pressure is caused by the swabbing effect of the drillstring moving
upwards.

5.7 KICK GAS

A kick (or an influx) of gas that enters into the wellbore, when the reservoir pore pressure exceeds the mud gradient, either while circulating or under static conditions.

5.8 EFFECT OF GAS CUTTING ON BOTTOM HOLE PRESSURE

Gas cutting can cause false indications of a kick. It will cause mud weight to be reduced at the surface and can also cause an apparent gain in the pits, often interpreted as a well flow. Pressure may also show up on the annulus if the well is shut-in.

Gas cutting only slightly reduces mud column pressure. Drilled cuttings from which the gas comes may increase mud column pressure and compensate for the decrease.

1 GENERAL

A kick is a flow of formation fluid and/or gas into the wellbore (refer to Section 3.1.2), the effects of which are normally measurable on the surface.

2 KICK DETECTION WHILE DRILLING

2.1 DRILLING BREAKS

A drilling break is defined as a doubling or halving of the ROP sustained over a 5' interval. All drilling breaks must be flow checked. Even if a flow check is negative, circulating bottoms-up may be advisable before continuing to drill ahead, e.g. HTHP wells, transition zones or reservoir intervals. The Toolpusher must be advised of all flow checks.

2.2 INCREASE IN FLOW RATE

The first positive indicator that the well is flowing is an increase in the return flow rate while the pumps are running at constant output.

2.3 INCREASE IN PIT VOLUME

A gain in pit volume is a positive indicator that a kick is occurring, assuming there are no other activities ongoing such as mud additions, mud transfers, start/stop of mud solids control or degassing equipment. Anyone influencing the active system volumes MUST communicate with the Driller prior to commencement and again upon completion.

2.4 VARIATION IN PUMP SPEED AND PRESSURE

Whilst drilling with constant parameters, a decrease in pump pressure (shunt motors) or an increase in pump speed (series motors) may occur when low-density formation fluids flow into the annulus causing a “U-tubing” effect.

Changes in the pump speed and pressure do not always mean an influx has entered the wellbore and may be an indication of pump problems, a washout in the drillstring, washed nozzles etc. First, conduct a flow check before proceeding with other diagnostic measures to determine the cause(s) of the variation.

2.5 WELL FLOWING DURING A CONNECTION

Annular flow with the pumps shut off may be a positive indicator that a kick is in progress.

An influx may occur during a connection due to the reduction in bottom hole pressure as the pumps are shut down (reduction of hydrostatic pressure from equivalent circulating density (ECD) to equivalent static density (ESD)).

2.6 CHANGE OF DRILLING FLUID PROPERTIES

Gas cut or fluid contaminated mud returning from the well could mean the well is kicking (refer to Section 4 Subsection 4).

Reduced mud weights can occur during drilling for many reasons; principally:

- Reduction due to the presence of formation fluids in the mud.
- Reduction due to gas cutting.
- The settling out of weighting material (barite 'sag').

3 KICK DETECTION WHILE TRIPPING

Flow into the wellbore will cause improper hole fill-up. Any deviation from expected hole fill volumes must be investigated and the first action must be to install a fully open safety valve and then make a flow check (refer to Section 4 Subsection 4).

If the flow check is positive the well must be shut-in immediately.

A negative flow check is not necessarily confirmation that an influx has not occurred. It is possible that the well will not flow even if an influx has been swabbed in.

If the hole does not take the correct volume of mud, or if the Driller has any doubt, the pipe must be run immediately and cautiously back to bottom and bottoms-up circulated.

1 CONTAINMENT AS EARLY AS POSSIBLE

When a well kicks, it should be shut-in within the shortest possible time. By taking action quickly, the amount of formation fluid that enters the wellbore and the amount of drilling fluid expelled from the annulus is minimized (Refer to Section 3 Subsection 2, Heading 2, Kick Size and Severity).

It is the Driller's (or the person performing the Driller's function) responsibility to shut-in the well as quickly as possible if a kick is detected or suspected using the procedure in Section 5 Subsection 3.

Clearly written, detailed procedures on the shutting in the well must be available to the Driller. Notices displaying the shut-in procedure must be posted on the drill floor.

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1 SHUT-IN PROCEDURES

See Figure 5.3.2, for the outline of Shut-In Procedures.

2 DRILLING - SURFACE BOP'S

The procedure is:

- Stop rotation.
- Pick up the drillstring to shut-in position.
- Stop the pumps and flow check - if the well flows:
  - Close annular and open remote control choke line valve (HCR).
  - Notify the Toolpusher and OIM (who must notify the Operator Representative).
  - Record and monitor shut-in drillpipe and casing pressures, pit gain and time.
  - Check space-out and close upper pipe rams and ram locks.
  - Bleed off pressure between pipe rams and annular (if possible without risking further kick).

3 DRILLING - SUBSEA BOP'S

The procedure is:

- Stop rotation.
- Pick up the string to shut-in position.
- Stop the pumps and flow check - if well flows:
  - Close the annular preventer (upper preferred), and open the choke line valves on the BOP stack.
  - Notify the Toolpusher and OIM (who must notify the Operator Representative).
  - Once the BOP is closed monitor the riser for flow and be prepared to divert if necessary.

    Note: a positive flow from the riser may be either gas in the riser or a leaking annular (refer to Section 8 Subsection 4 Item 9 & 9.3).
  - Record and monitor the shut-in drillpipe and casing pressures (note fluid density in choke/kill lines). Record the gain in pit volume and time of day.
  - Confirm the space-out and close the designated hang-off rams with reduced closing pressure. Reduce the annular pressure (see

manufacturer's guidelines), slack off and land drillstring on the rams using the drillstring compensator (DSC).

- Increase the manifold pressure back to 1500 psi. Engage ram locks.
- Bleed off pressure between pipe rams and annular (if possible) and open annular.
- Adjust the DSC to support the drillstring weight to the BOP plus 20,000 lbs. Position the DSC at mid-stroke.

4 TRIPPING - SURFACE BOP'S

The procedure is:

- Set the slips below the top tool joint of the stand.
- Install and close the full opening safety valve.
- Close annular and open HCR valve on choke line.
- Notify the Toolpusher and OIM (who must notify the Operator Representative).
- Make up the topdrive/kelly (insert pup joint or single between safety valve and topdrive) and open the safety valve.
- Record and monitor shut-in drillpipe and casing pressures, gain in trip tank volume and time.
- Torque up all joints and prepare to strip back to bottom.

5 TRIPPING - SUBSEA BOP'S

The procedure is:

- Set the slips below the top tool joint of the stand.
- Install and close the full opening safety valve.
- Close the annular preventer (upper preferred) and open the choke line 'fail-safe' valves on the BOP stack.
- Notify the Toolpusher and OIM (who must notify the Operator Representative).
- Monitor the riser for flow (refer to Section 8 Subsection 4 Item 9 & 9.3).
- Make up the topdrive/kelly (insert a pup joint or single between the topdrive and the safety valve) and open the safety valve.
- Open the drillstring compensator (DSC).
- Record and monitor the shut-in drillpipe and casing pressures, gain in trip tank volume and time.

- Torque up all joints and prepare to strip back to bottom.

If unable, try to make-up top drive to string. If unsuccessful shear pipe or drop string. The preferred action is to return the pipe as close as possible to bottom. If the OIM decides to strip back in the hole refer to Section 6 Subsection 5.

6 WHILE OUT OF HOLE

The procedure (Surface and Subsea BOP's) is:

- Close blind/shear rams and open remote operated valve.
- Notify the Toolpusher and OIM (who must notify the Operator Representative).
- Subsea BOP's: Monitor the riser for flow (refer to Section 8 Subsection 4 Item 9 & 9.3).
- Allow pressure to stabilize and record casing pressure and pit gain, while running drillstring down to the top of the BOP's.
- Stripping procedures must be planned according to the well pressure.

7 CASING RUNNING

The following must be prepared prior to running casing:

- Careful consideration must be given to the use of casing rams, which will be dependent on the inherent risks of the section to be cased. The decision tree for casing rams (Figure 5.3.1) should be used to assist in the decision as to whether casing rams will need to be installed
- Record the annular volume between the casing and open hole/ outer casing and calculate acceptable running speeds by depth with respect to surge pressures.
- Prepare a volume displacement schedule for monitoring volumes.
- Have a circulating head on the drill floor. Check correct thread type by physical installation and have it prepared without protectors for rapid installation.
- On floating rigs, ensure a XO from casing to drillpipe is available.
- At least one and preferably two non-return valves shall be installed in the casing string when running into a hydrocarbon bearing zone. This would normally be a valve in the float collar and one in the shoe

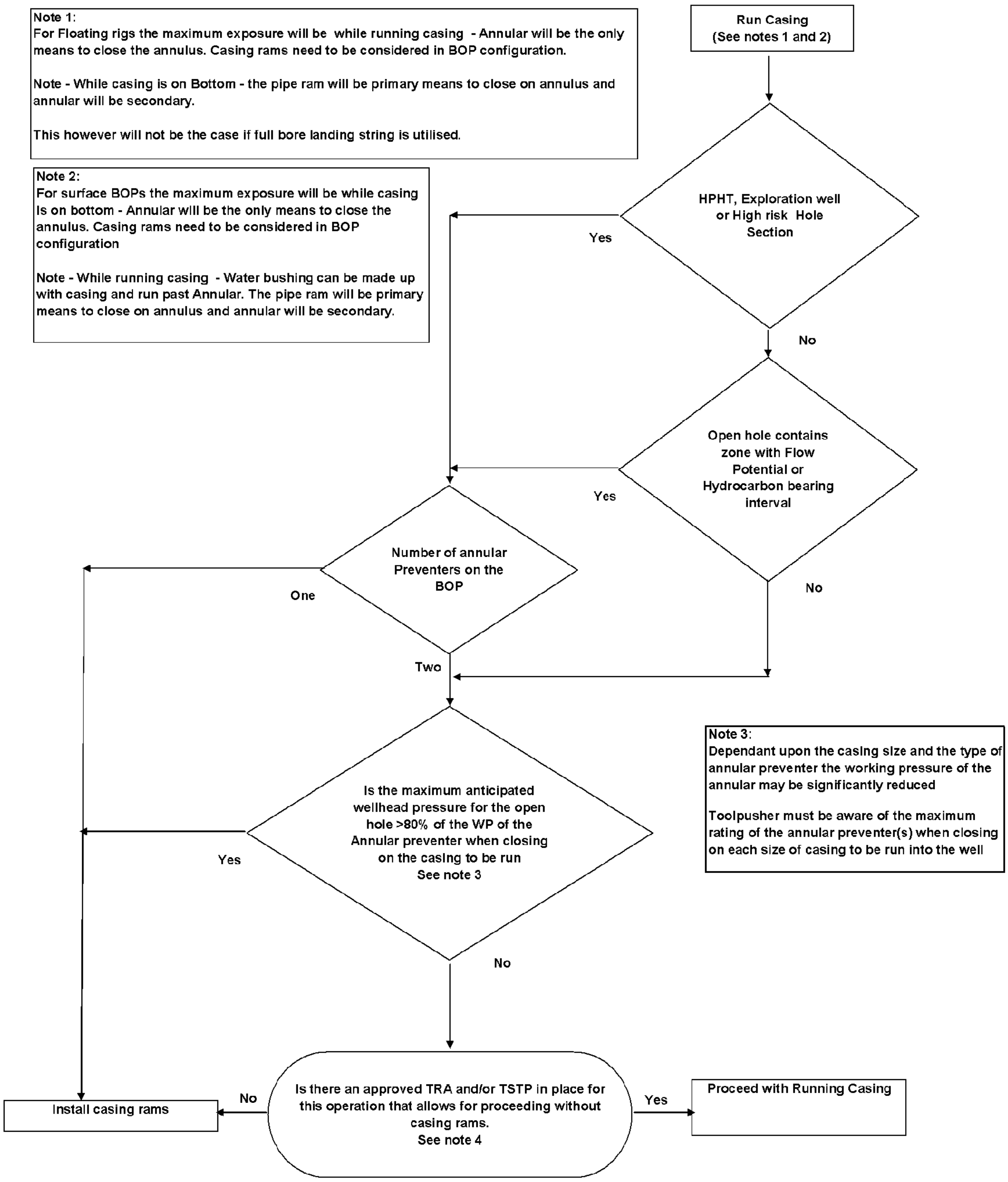
The following should be considered for shutting-in on casing:

- The immediate priority is to shut-in the well. (NOTE: Reduce annular/ram operating pressure to account for size and type of casing across the BOP).
- The most suitable control technique can only be determined after assessing the particular conditions at the rig site.
- The subsequent options available can be summarized as follows:
  - XO to drillpipe (unless the current casing string weight is too great) and strip to bottom to kill the well.
  - XO to drillpipe, strip in until the drillpipe is in the stack. Perform a top kill.
  - Kill the well with the casing across the stack, (possibly using the Volumetric Method first). The possibility of disconnect must be considered.
  - Bullheading.
- Drop the casing.
- Shear the casing.

The major factors that will determine the most appropriate course of action will include the following:

- The length and type of casing run.
- The possibility and consequences of the casing becoming stuck.
- The feasibility of circulating out a kick by conventional means (the smaller annular clearance may cause excessive pressures in the annulus, or might completely restrict circulation).
- The feasibility of killing the well by other means such as bullheading or by volumetric control.
- The BOP stack design and ram types.
- The casing being forced out of the hole by the well pressure.
- The weather.
- The possibilities of a disconnect due to blackout, drive-off, etc.

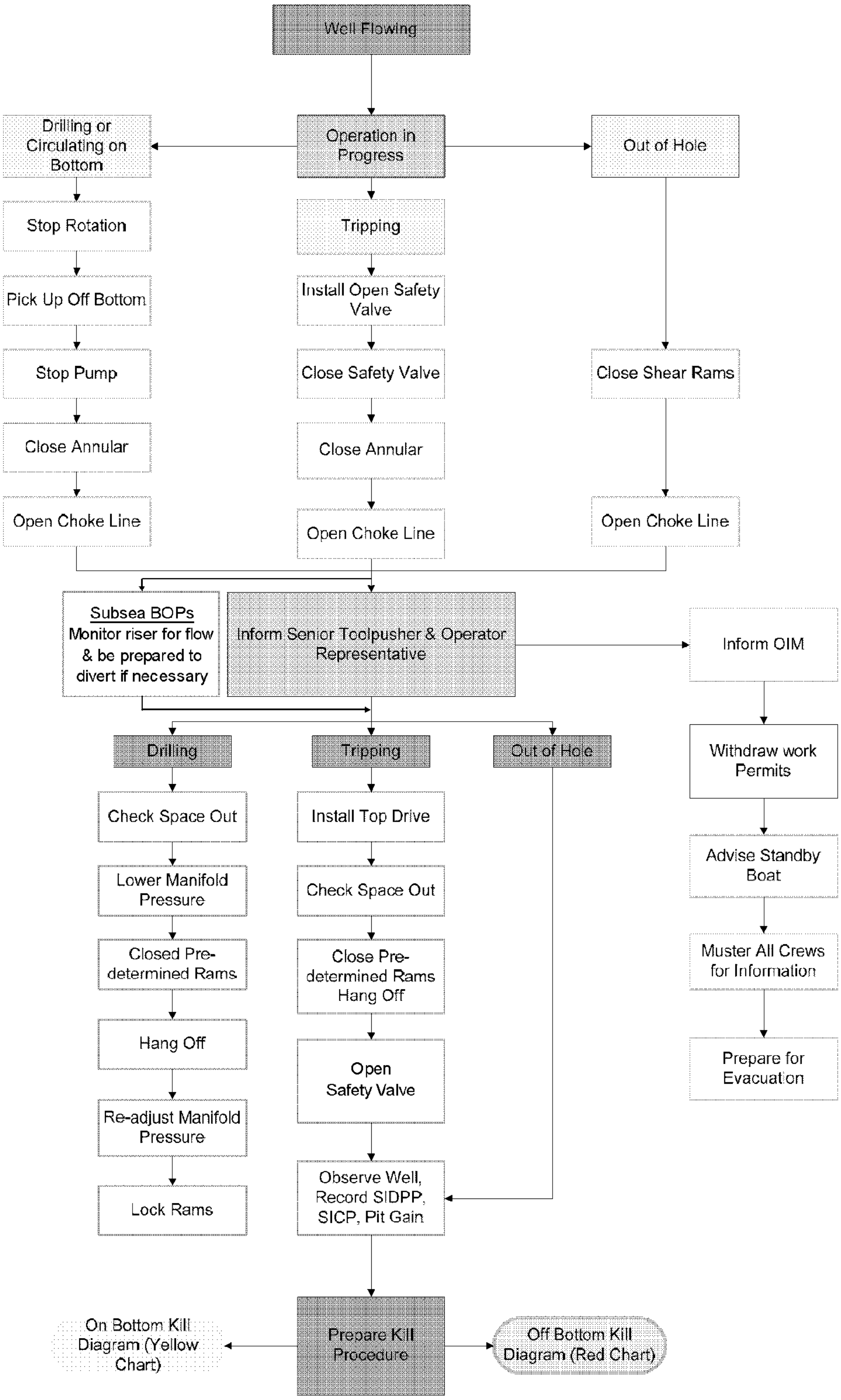
Figure 5.3.1, Casing Ram Decision Tree



Note 4:
Considerations for TRA/TSTP:
Reservoir knowledge and experience
Problems when drilling the section (losses, kick etc)
Ability to move off location - Floaters
Ability to drop the casing
Run on Drillpipe or fullbore landing string - Floaters
Liner (length of liner vs water depth) - Floaters
What is across the BOP at the various stages of the operation (running, landing, cementing etc.)
Amount of work the annular has completed since last inspection
Ability to shear the casing
Collapse rating of the casing to be run

Figure 5.3.2, Shut-In Procedures

TRANSOCEAN SHUT-IN PROCEDURES



1 MONITORING ON TRIP TANK

- Check trip tank line-up and circulate the well over the trip tank to confirm the mud level in the riser.
- Bleed the pressure from between the annular and the rams, where applicable, if possible. After the pressure has been bled off, open the annular.
- Continue monitoring the riser volume.

2 WELL CONTROL WITH A KILL JOINT

If required, the topdrive/ kelly can be changed out for a high-pressure Kill Joint, complete with high-pressure hose, if the SIDPP approaches (or is predicted to approach) the maximum pressure rating of the equipment or (on floating rigs) the DSC is inoperative.

3 PRESSURE AND PIT VOLUME/ TRIP TANK READINGS

Once the well is shut-in, monitor its behavior carefully by doing the following.

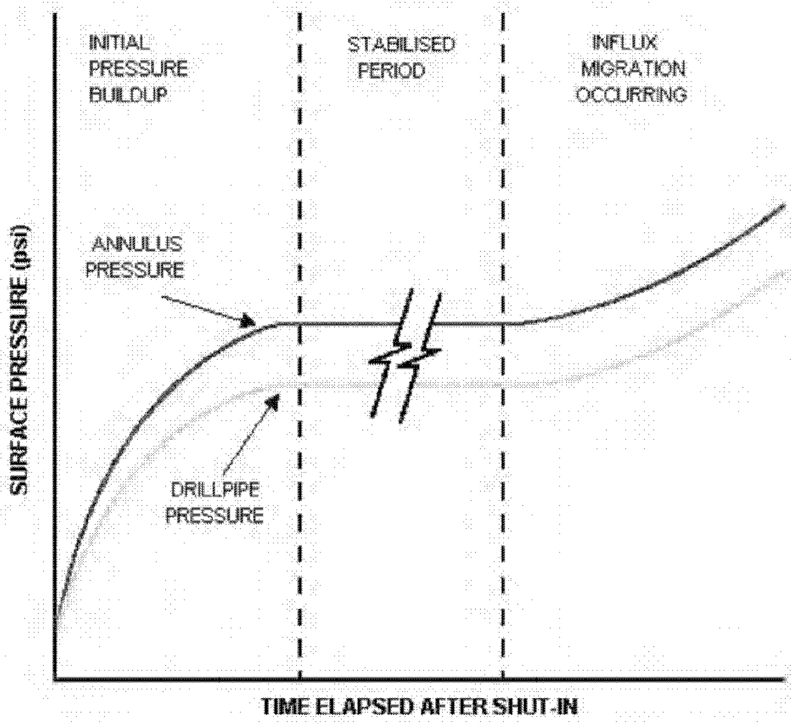
- Record the pit gain.
- Continue to monitor the well on the trip tank to make sure that the BOP's are not leaking.
- The SIDPP and SICP should be recorded initially at 1-minute intervals until the pressures have stabilized. It is important to record the data frequently in order that any change in the rate of build up can be clearly identified (refer to Well Control Records form in Section 10 Subsection 2.4).
- Usually, the rate of build up is relatively fast until the well begins to stabilize. Once the pressures have begun to stabilize, any further significant increase in both SIDPP and SICP may be indicative of kick migration.
- If surface pressures take a considerable time to stabilize, it may be due to one, or all, of the following:

  The kick formation is a low permeability zone.
  The kick created instability in the wellbore, leading to the hole sloughing and packing off.

  The kick is migrating up the hole.
  The surface lines or subsea choke line are partially plugged.
  An underground blowout is in progress
  Leak between casing strings has developed

The shut-in drillpipe pressure reflects the difference between the kick zone pressure and the effective hydrostatic pressure of the mud column in the drillpipe, assuming that the influx has not entered the drillstring. It can therefore be used to determine the kick formation pressure.

Figure 5.4.1, Surface Pressures After Shut-In



4 RECORDING DRILLPIPE PRESSURE WITH A NON-PORTED FLOAT VALVE

If a non-ported float valve is in the string and a kick is taken, the valve will close against the differential pressure and zero pressure will be recorded at the standpipe, assuming no trapped pressure.

A typical method to determine shut-in drillpipe pressure follows the same principles as performing a LOT:

- Pump into the closed wellbore through the drillpipe at a slow rate or by using the hesitation method and closely monitor the drillpipe and shut-in casing pressures.
- When the rate of increase of the drillpipe pressure changes significantly, or the casing pressure just begins to rise, shut off the pump and record the drillpipe pressure. This value will be the shut-in drillpipe pressure.

5 TRAPPED PRESSURE

In some circumstances it is possible that the pressure, in excess of that caused by the kick zone, can be trapped in the well. There are four possible causes of this phenomenon:

- The pumps were left running after the well was shut-in.
- The influx is migrating up the hole.
- Pipe has been stripped into the well without bleeding off the correct volume of mud.
- Dynamic forces within the mud due to pressure and temperature (especially in HP/HT wells).

Trapped pressure of this kind will result in surface pressures that do not reflect the actual kick zone pressure. However, if the surface pressure has built up immediately after the well was shut in, this is confirmation that there is no trapped pressure in the well.

The following procedure can be used to check for trapped pressure:

- Using a manual choke, bleed a small volume (1/4 - 1/2 bbls, 0.04 - 0.08 m3) of mud from the annulus to a suitable measuring tank.
- Close the choke and allow the pressure(s) to stabilize.
- If pressure has been trapped in the well, the drillpipe pressure and casing pressure will have fallen by approximately an equal amount.
- If the drillpipe pressure does not drop after bleeding mud from the annulus, no pressure is trapped in the well. If there is no trapped pressure in the well, each increment of mud bled from the well will cause a further influx into the well. Therefore, if no reduction in drillpipe pressure is detected after bleeding 2-3 bbls (0.3-0.4 m3) from the well, no more mud should be bled off.
- An increase in casing pressure is a sign that additional influx has entered the well. If this occurs, no more mud should be bled from the well.
- If both the drillpipe pressure and casing pressure have decreased, continue to bleed mud from the well in (1/4 - 1/2 bbl, 0.04 - 0.08 m3) increments.

- When the drillpipe pressure no longer decreases as the mud is bled from the well, stop bleeding mud and record the drillpipe pressure as the shut-in drillpipe pressure.

While it is undesirable to overkill the well, it is potentially hazardous to increase the size of the influx, which is a possibility if this procedure is not properly carried out. If there is some doubt as to the true shut-in drillpipe pressure, even after bleeding mud from the annulus, it may be prudent to use the Driller's method to circulate out the kick, rather than continue bleeding mud.

6 KICK MIGRATION

Kick migration in a shut-in well can cause excessive pressures within the wellbore if suitable control procedures are not implemented.

Procedures for relieving bottom hole pressure, due to migration, will depend on both:

- The position of the drillstring in the hole.
- Ability to monitor BHP with SIDPP.

In both cases, control will be by the Volumetric Method (refer to Section 6 Subsection 3).

7 HEIGHT AND GRADIENT OF A KICK

Kick gradient is not required for the kill procedure, but can be useful to determine the magnitude of annulus pressures expected and will help with the planning, handling and disposal of the kick when it arrives at surface (refer to Section 10 Subsection 3).

Kick Gradient			**Kick Type**
(psi/ft)	**(kPa/m)**	**(bar/m)**	
0.05-0.2	1.1-4.5	0.01-0.05	Gas
0.30-0.4	6.8-9.0	0.07-0.09	Oil
>0.4	>9.0	>0.09	Water

The following assumptions are made:

- Gradient of the mud in the annulus above the kick is uncontaminated.
- Annular volume is based on gauge hole.
- Kick volume is accurately recorded.

As such, care must be taken with interpretation; the gas gradient should be considered for safety and critical decisions, as this is the "worst case".

If long choke and kill lines are filled with water or other fluids, the gradient of the kick is given by:

$$Gi = Gm - \frac{(SICP - [Lchoke \times (Gm - Psw)] - SIDPP)}{Hi}$$

Where:

Gi	= Kick gradient
Gm	= Mud gradient
Lchoke	= Length of choke line
Psw	= Gradient of sea water or other liquid
SIDPP	= Shut-in drillpipe pressure
Hi	= Height of influx
SICP	= Shut-in casing pressure

8 DETERMINING OVERBALANCE

The Company approved method is to calculate KMW equivalent to formation pressure with the only overbalance coming from “rounding up” the calculated KMW. If the decision is made to provide more overbalance when killing the well, applying additional choke pressure is preferable to increasing the mud weight as this allows immediate BHP adjustment should mud losses or other problems develop.

Once the well has been killed, the mud weight can be increased further to include a trip/safety margin (refer to Section 10 Subsection 4, Well Control Formula).

For wells where there is a known large margin between pore pressure and fracture pressure, consideration should be given to including a trip/safety margin with the KMW. This will minimize the chance of swabbing a kick once the well has been initially killed.

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1 PROCEDURE

Once a well has been shut-in, the influx must be removed from the well in a controlled manner and without permitting the further entry of formation fluids into the wellbore. Several methods of controlling an influx exist, some with circulation and some without.

There are three basic methods, all of which aim at maintaining bottom hole pressure constant and equal to or slightly greater than formation pressure.

- The Wait and Weight Method.
- The Driller's Method.
- The Volumetric Method (only required in special situations).

NOTE: Assuming conditions are safe to do so, remotely monitor well control equipment during well kill operations. For subsea stacks, this includes launching of the subsea camera or ROV to observe for component failures.

1.1 WAIT AND WEIGHT METHOD

This method involves one circulation and is generally the preferred method. However, the well kill method should always be selected based on the actual wellbore conditions. Kill mud is prepared and is pumped from surface to the bit while following a calculated drillpipe pressure drop schedule. Once the kill mud enters the annulus, a constant drillpipe pressure is maintained until the kill mud arrives at surface. (Refer to Section 10 Subsection 2.1 for blank Transocean Kill Sheet in oilfield units for both surface and subsea applications, vertical and deviated wells.)

The following procedure must be followed:

1. Once the kill sheet has been completed and the mud weight has been raised to the desired value, prepare to circulate through choke.

2. Open choke manifold valve upstream of choke (or downstream if applicable), zero stroke counters, ensure good communication between choke operator, mud pump operator and personnel in the pump room.

3. Bring the pump to kill rate speed while holding casing pressure constant. For subsea well control operations, reduce the casing pressure by an amount equal to the choke line friction loss (CLFL) – see Section 10, Subsection 8.

4. Once the pump is up to speed and the pressures have stabilized, record the actual circulating drillpipe pressure. If the actual circulating pressure is equal to, or reasonably close to, the calculated initial circulating pressure (ICP), continue pumping and follow the standpipe pressure according to the drillpipe pressure schedule.

   Any marginal difference between the actual and calculated ICP is most likely due to the fact that the SCRP used to calculate the ICP may not be relevant to the conditions at the time of taking the kick.

   The actual SCRP, and hence the corrected final circulating pressure, F C P, can be determined from the initial circulating pressure as follows:

   Actual SCRP = Actual Initial Circulating Pressure - SIDPP
   FCP = Actual SCRP x (Kill Mud Weight ÷ Original Mud Weight)

   The drillpipe pressure schedule must be corrected to take into account the adjusted circulating pressures.

   If the actual circulating pressure is significantly different from the calculated ICP, stop the pump, shut the well in, and investigate the reason. Ensure there is no trapped pressure (refer to Section 5 Subsection 4 Item 5).

5. From the moment pumping of the weighted mud begins, until the end of the well kill process, constant BHP must be maintained.

6. When the kill mud enters the annulus, the choke operator then holds drillpipe pressure constant until the kill mud returns at surface. On subsea wells in deeper water, due to the increase in CLFL caused by the kill mud, the drill pipe pressure will increase towards the end of circulation – see Section 8, Subsection 4, Item 8.5.5 – Finishing Kill.

7. Any time the circulation is interrupted and the well shut-in during the kill operation, it will be necessary to ensure that no pressure has been dynamically trapped and that the BHP is equal to the formation pressure before resuming the kill operation.

8. Once uncontaminated kill mud returns are observed at surface, shut-in the well and monitor the drillpipe and casing pressures.

   If any pressure is found, the reason for it must be investigated and additional steps taken as explained in Section 5 Subsection 4 Item 5.

If no pressure is measured, the well must be flow checked through the choke before opening the BOP's.

9. On floating rigs, the riser must be displaced to the kill weight mud and any gas trapped in the BOP's removed before opening the BOP's (refer to Section 6 Subsection 8).

10. To help in identifying the cause of potential problems, it is important to maintain an accurate record of times, pressures, volumes, etc. on the well control kick report. Normally the Driller or his assistant will be assigned this task.

1.2 ADVANTAGES AND DISADVANTAGES

Advantages include:

- In some circumstances, it will generate the lowest pressure on the formation near the casing shoe.
- With a long open hole section, it is the least likely method to induce lost circulation. This difference is most significant if the influx contains gas and is a high intensity (large under balance) kick.
- In most circumstances, it will generate the lowest pressure on the casing and surface equipment.
- Requires one less circulation than the Driller's Method.
- Least time spent circulating through the choke(s) and least time the equipment is exposed to excess pressure.

Disadvantages include:

- Requires longest waiting time prior to circulating the influx from the wellbore.
- In a case where a significant amount of hole is drilled prior to encountering the kick zone, the cuttings could settle out and plug the annulus.
- Gas migration might become a problem while the mud weight is being increased.
- Sufficient weighting agent necessary to increase mud weight may not be present on site. In this case it may be desirable to circulate the influx from the wellbore and then kill the well when the weighting material arrives.

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1 PROCEDURE

This method requires two circulations. During the first circulation, the drillpipe pressure is maintained at a constant value using existing mud weight until the influx is circulated from the well.

During the second circulation, kill mud weight is pumped to the bit while following a drillpipe pressure schedule.

If all of the influx is successfully circulated from the well in the first circulation then during the second circulation, the casing pressure should remain constant as the drillpipe pressure reduces from ICP to FCP.

When the kill mud enters the annulus, FCP is maintained constant until the kill mud reaches surface.

1.1 FIRST CIRCULATION:

1. Once the pressures have stabilized, the pump is brought up to kill rate speed while holding the casing pressure constant (less CLFL for subsea BOP's). For subsea well control operations, reduce the casing pressure by an amount equal to the choke line friction loss (CLFL) – see Section 10, Subsection 8.
2. If the observed pressure is greater or lower than the expected pumping pressure, subsequent calculations will be based on this new value of ICP (refer to Section 10 Subsection 1 Item 2.1).
3. When the kill rate speed is established, the choke operator should switch to the drillpipe gauge and hold this pressure constant until the influx is removed from the well.
4. Shut-in the well and record SIDPP and SICP prior to beginning the second circulation (they should be approximately equal).
5. The active mud system should be weighted up to the proper kill mud weight and lined up on the selected mud pump.
6. Prepare a drillpipe pressure schedule, as was done with the 'Wait and Weight' method.

1.2 SECOND CIRCULATION:

1. The pump is brought up to kill rate speed while holding the casing pressure constant (less CLFL for subsea BOP's). For subsea well control operations, reduce the casing pressure by an amount equal to the choke line friction loss (CLFL) – see Section 10, Subsection 8.

2. When the kill rate speed is established, switch to the drillpipe gauge and follow the drillpipe pressure schedule until the kill mud reaches the bit.
3. At this point hold drillpipe pressure (FCP) constant until the mud returns at surface. On subsea wells in deeper water, due to the increase in CLFL caused by the kill mud, the drillpipe pressure will increase towards the end of circulation – see Section 8, Subsection 4, Item 8.5.5 – Finishing Kill.
4. Once uncontaminated kill mud is observed at surface, shut-in the well and monitor drillpipe and casing for pressure.
5. If any pressure is found, the reason for it must be investigated and additional steps taken.
6. If no pressure is registered the well must be flow checked through the choke before opening the BOP's.
7. On floating rigs, the riser must be displaced to the kill weight mud and any gas trapped in the BOP's removed before the BOP's are opened.
8. To help in identifying the cause of potential problems, it is important to maintain an accurate record of times, pressures, volumes, etc. on the well control report. Normally the Driller or his assistant will be assigned this task.

2 ADVANTAGES AND DISADVANTAGES

Advantages include:

- Can start circulation right away if hole conditions warrant.
- Able to remove hydrocarbons from the well even if limited barite available on location.
- Less chance of gas migration.
- Drillpipe pressure schedule is not absolutely required if all the influx was removed from the well in the first circulation and no additional influx was taken.

Disadvantages include:

- Highest surface pressures for longest period.
- In certain situations, highest shoe pressure.
- One more circulation required than Wait and Weight Method.
- More time circulating through the choke(s).

1 PROCEDURE

If a gas kick cannot be circulated from the well, gas migration may occur resulting in high surface, casing shoe and bottom hole pressures. To minimize this, it is necessary to allow the influx to expand in a controlled fashion as it migrates up the wellbore. The volumetric method maintains BHP slightly above formation pressure.

This technique may be used under the following circumstances:

- Gas migration while waiting to start/restart an operation.
- Drill bit is plugged.
- Drillstring has failed allowing communication between drillstring and annulus.
- Drillstring is off-bottom, causing drillpipe and casing pressures to read the same until the influx has migrated above the bit.
- Drillstring is out of the hole entirely.

1.1 DRILLSTRING COMMUNICATION

If pumping is not an option and gas migration is suspected due to a steady increase in drillpipe and annulus pressure, apply the volumetric method using the drillpipe gauge if the bit is at or near to bottom.

1. Record SIDDP and SICP at fixed intervals and determine the migration rate.
2. Allow SIDPP to build up to an overbalance margin (normally 100-200 psi, 700-1400 kPa, 7-14 bar).
3. Allow the SIDPP to build up by an operating margin 50-150 psi, 350-1050 kPa, 3.5-10.5 bar).
4. Bleed mud slowly from the choke manifold until the drillpipe pressure has reduced to the original stabilized shut-in value plus the overbalance margin.
5. Continue until the kick has reached the BOP's or circulation can commence.

1.2 NO DRILLSTRING COMMUNICATION

If the drillstring becomes plugged when on bottom, the bit is off bottom or out of the hole and gas is migrating, the situation becomes more complicated.

1. Monitor SICP allowing it to increase approximately 100-200 psi (700-1400 kPa, 7-14 bar) above the original shut-in pressure for an overbalance.

2. Calculate the hydrostatic pressure exerted by a barrel (m^3) of mud in the annulus.

$$= \frac{\text{Mud Gradient}}{\text{Annular Capacity}} \qquad (\text{psi/bbl, kPa/m}^3\text{, bar/m}^3)$$

If there is no pipe in the hole:

$$= \frac{\text{Mud Gradient}}{\text{Hole Volume}} \qquad (\text{psi/bbl, kPa/m}^3\text{, bar/m}^3)$$

3. Calculate annulus capacity based on drillpipe in a gauge hole, or if no drillpipe use gauge hole volume.
4. Monitor the SICP while allowing it to increase an additional 50-150 psi (350-1050 kPa, 3.5-10.5 bar) operating margin.
5. Calculate the volume of mud in the annulus that would contribute a hydrostatic pressure equal to the selected casing pressure increase.

$$= \frac{\text{Casing Pressure Increase}}{\text{Ph exerted by each (bbls, m}^3\text{) of mud}} = \text{Vol. to bleed (bbls, m}^{3)}$$

6. Hold the casing pressure constant until the amount of mud calculated is bled off into the trip tank or another calibrated tank.

   NOTE: For the initial bleed-offs, this may take a considerable period of time.
7. Keep a record of time, pressures and volumes.
8. Repeat this sequence of allowing casing pressure increases and then bleeding a calculated volume until the influx reaches the surface.
9. Once the gas is at surface, stop the bleeding process.
10. If more gas is bled from the annulus at this point, the BHP will drop below formation pressure and another influx will result.

1.3 LUBRICATION

With gas at the BOP, casing pressure can be reduced by lubrication as follows:

1. Slowly pump a selected volume of mud into the annulus and allow the mud to fall through the gas.

2. A small pressure increase may occur due to the gas being compressed by the mud being pumped in.
3. Bleed gas allowing casing pressure to fall an amount equal to the hydrostatic pressure of the mud pumped into the well.

- If the annulus pressure increases during the pumping-in procedure, the amount of this increase should be bled off in addition to the pressure bled for the hydrostatic pressure increase.
- If mud starts coming back, shut the choke and wait for the gas to work up to the surface before continuing to bleed off.

4. Repeat until all the gas has been bled off or the desired surface pressure is reached.

1.4 ADVANTAGES AND DISADVANTAGES

1.4.1 ADVANTAGES

- Can be used to prevent wellbore pressures from increasing due to gas expansion.
- Does not require circulation and can therefore be used when circulation is not possible.

1.4.2 DISADVANTAGES

- The precise diameter of the open hole, required for the calculations, is unknown.
- Dependent on influx migration.

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1 PROCEDURE

This technique can be used as an alternative to the Static Volumetric Method. However, it should only be used as a method of safely venting an influx from below a subsea stack, due to both the complexity of the operation and the level of stress imposed on well control equipment during circulation.

Experience has shown that the Dynamic Volumetric Method is the most reliable method of venting gas from a subsea stack, if the drillpipe cannot be used to monitor bottomhole pressure.

For wells drilled in deepwater, this method is recommended in preference to the (Static) Volumetric method.

As the influx migrates above the wellhead, gas is forced into the subsea choke line, which has a much smaller cross sectional area than the annulus. With this configuration, the static volumetric method is much more difficult to implement, since gas entry into the subsea choke line must be detected.

Additionally, gas distribution and migration rate must be known in order to make appropriate changes in the casing pressure-pit gain schedule.

The principle of the procedure is identical to the Static Volumetric Control. However, the implementation is considerably different. In this case, circulation is maintained across the wellhead, while the surface pressure and pit gain are controlled with the choke. The kill line pressure is used to monitor the well.

It is very important that the active tank be a suitable size to resolve very small changes in level. It should be possible to reliably detect changes of the order of one barrel.

Having identified that the influx is at the stack, the following guidelines can be used to implement the Dynamic Volumetric Method.

1. Ensure that the kill line is full of mud.

If there is any possibility that the kill line contains gas, the well should be isolated and the kill line circulated to mud. This will ensure that the pressure at the stack is accurately monitored during the operation.

2. Circulate down the kill line and up the choke line.

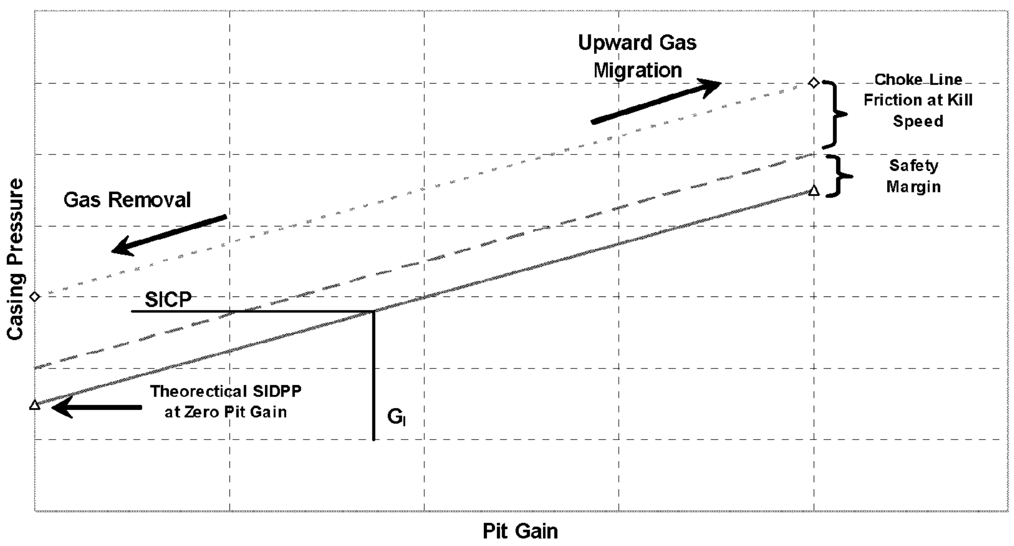
Ensure that it is possible to monitor the active pit level accurately. Route returns through the mud gas separator.

3. Bring the pump up to speed

As the pump is brought up to speed, the kill line (or pump pressure) must increase by an amount equal to the kill line pressure loss. However, if it is not possible to compensate for the choke line pressure loss, the kill line pressure will inevitably increase by more than the kill line pressure loss.

The kill line circulating pressure must be monitored during the operation to remove gas from the well.

Figure 6.4.1, Dynamic Volumetric Kill



4. Reduce kill line pressure in line with drop in pit level

As gas is removed from the well, the pit level will drop while the choke operator adjusts the choke to maintain a constant kill line circulating pressure. This will result in mud being lubricated into the well. If the kill line circulating pressure is held constant as mud is lubricated into the well (as gas is removed), the bottomhole pressure will increase. Therefore, as the pit level decreases, the kill line pressure should be reduced to account for the greater hydrostatic pressure in the annulus.

Example

Drop in pit level	= 5 bbls
Annulus	= 8 1/2" x 5"
Mud weight	= 14.0 ppg

Hydrostatic pressure equivalent of mud (psi/bbl):

$$= \frac{14.0 \times 1029.4 \times 0.052}{(8.5^2 - 5^2)} = 15.86 \text{ psi/bbl}$$

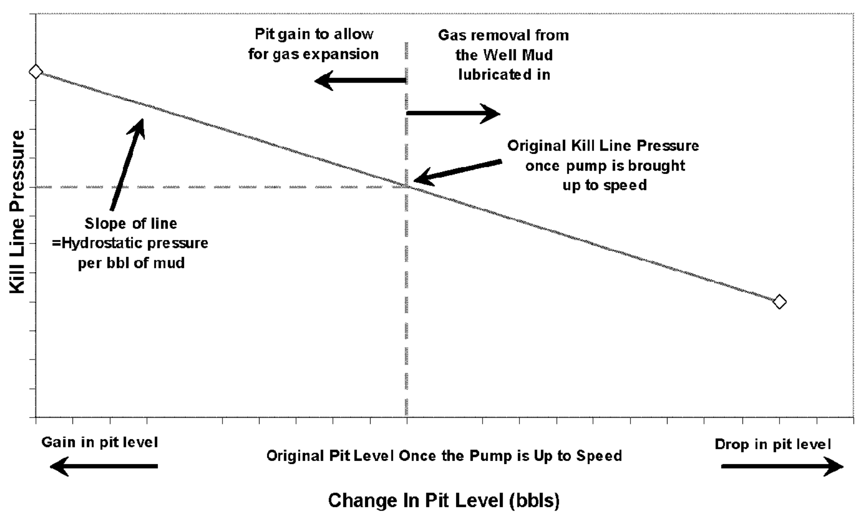
Therefore, reduce kill line circulating pressure by 15.86 x 5 – 79.3 psi.

This procedure should be continued until all the influx has been removed from the well. This will be indicated by a constant pit level.

If the well has been completely killed by removing gas from the stack, the final circulating kill line pressure will be equal to the sum of the kill line pressure loss, the choke line pressure loss and the wide open choke pressure. If the well is not yet completely killed at this point, the final circulating kill line pressure will be greater than this value.

See Figure 6.4.2 for an example kill line pressure schedule for this method.

Figure 6.4.2, Dynamic Volumetric



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1 PROCEDURE

When the drillstring is partially or completely out of the hole and an influx or swabbing is experienced, every effort should be made to return the bit to bottom, while maintaining well control, as the well can be most effectively killed with the bit on bottom.

For both surface and subsea stacks, the recommended procedure is to install an inside BOP (IBOP) and strip through the annular preventer using the combined stripping and volumetric method until the bit is returned to bottom or until further stripping becomes impossible.

It requires knowledge of equipment and procedures used by all crews and practice drills as required. *(*Refer to Section 4 Subsection 2 Item 6*).*

NOTE: In deepwater, consideration may be given to performing a top kill (e.g. weighting up the riser) prior to attempting to strip through the subsea BOPs.

1.1 PREPARATION

- Have an additional full opening safety valve available on the drill floor during stripping operations.
- Remove all drillpipe/casing protector rubbers.
- Lubricate the string with grease and/or, if a surface stack, pour oil on top of the annular.
- Ensure the tool joints are smooth.
- Apply the lowest practical closing pressure to the annular preventer while avoiding leakage.
- A “stripping checklist” must be available on each rig to assist supervisors before and during this well control operation.

NOTE: If drillpipe >5" OD is to be stripped, modification of fingers on some annulars may be required - check with manufacturers. (Refer to Section 10 Subsection 2.2 for stripping sheet.)

1.2 OPERATION

- Install an inside BOP above the full opening safety valve or pump a drop in check valve (dart sub).
- Open the full opening safety valve prior to stripping and make sure the inside BOP is not leaking.

- The packing element of an annular preventer must be allowed to breathe slightly when a tool joint passes through. Recommended BOP closing pressures can be obtained from the manufacturer's BOP operating manuals.
- If installed on surface stacks, a surge bottle connected to the closing line of the annular preventer will improve effective BOP control during stripping tool joints through the annular preventer; adjust its pre-charge to the required value before starting the stripping operation.
- Stripping speeds should not exceed 2 ft/sec.
- It is recommended to vent the opening chamber control line of the annular preventer (Cameron D-type) to improve stripping tool joints through the preventer.
- Watch the flowline for any leakage. Any returns are to go back into the trip tank.
- Accurately measure and record mud volumes bled-off using the trip tank. If available, a separate stripping tank may be used.
- Keep the string full, measure and record mud volumes used to fill the string.
- Monitor the marine riser of a subsea BOP stack for gains and take the effect of heave and tidal changes into account when stripping.

1.3 STRIPPING THROUGH ANNULAR PREVENTERS

During stripping operations a constant bottom hole pressure must be maintained at all times. Accurate monitoring of pressures and volumes of mud bled off from the casing is essential. The following must be taken into account when stripping:

Compensate for the volume of pipe being introduced into the hole.

- In the absence of influx migration the SICP should be kept constant by manipulating the choke as pipe is being stripped into the well. If there is no gas migration and the BHA does not enter the influx, the resultant volume bled off to the trip tank should equal the closed end displacement.

Allow for an increase in surface pressure as the BHA enters the influx.

- As the BHA enters the influx, the height of the influx will increase dramatically as it is displaced from below the bit into the open hole-drill collar annulus.
- As it may be difficult to estimate exactly when the BHA will enter the influx, the following procedure includes a safety factor to account for the estimated pressure increase due to entering the influx (P_{saf}). This safety factor is added to the choke pressure at the start of stripping operations.

Allow for gas migration.

- Gas or influx migration will be indicated by a gradual increase in either pressure (if shut-in) or an increase in the volume bled back when maintaining a constant choke pressure. The following procedure accounts for any gas/influx migration using a volumetric method which is nothing more than adding additional choke pressure to account for decreased hydrostatic as the gas migrates and is allowed to expand.

1.3.1 STRIPPING PROCEDURE

The following procedure adopts a constant choke pressure approach. The choke pressure is initially calculated based on the SICP and appropriate safety factors. Choke pressure is only increased if there is evidence of gas migration. In such cases the choke pressure is increased in steps (typically 50 or 100psi) once a volume of mud (with an equivalent hydrostatic pressure of 50 or 100psi) in excess of the closed end displacement is bled back to the stripping tank.

Safety factors to obtain sufficient overbalance, in particular when the drill string enters the influx, are incorporated in this method.

A. PRIOR TO COMMENCING STRIPPING

1. After shutting in the well, record SICP and determine the influx volume. Closely monitor SICP for any signs of gas migration.

2. Calculate P_{choke} as described below. Upon commencement of stripping the choke pressure will be allowed to increase to Pchoke.

$$P_{choke} = SICP + P_{saf} + P_{step}$$

SICP = Initial Shut-in Casing Pressure.
P_{step} = working pressure increment (Typically 50-100psi)
P_{saf} = allowance for loss of hydrostatic pressure as the influx rises from below the bit to around the drill collars calculated as below:

$$P_{saf} = (V_{inf} / Cap_{OH/DC} - V_{inf}/ Cap_{OH}) \times (G_{mud} - G_{inf})$$

V_{inf} = initial Volume of the influx (Pit Gain)
$Cap_{OH/DC}$ = Open Hole/Drill Collar annular capacity
Cap_{OH} = Open Hole capacity

G_{mud} = mud gradient
G_{inf} = estimated influx gradient

Convenient values of P_{step} are between 50-100 psi (350-700 kPa, 3.5-7 bar), bearing in mind the scale divisions of available pressure gauges.

3. Calculate the closed end displacement of the tubulars to be stripped in.

$$\text{Tubular Closed End Displacement (bbl/ft)} = OD^2/1029.4$$

4. Calculate $Hyd_{OH/DP}$ which is the hydrostatic pressure exerted per bbl of mud in the drill pipe/open hole annulus (psi/bbl).

$$Hyd_{OH/DP} = G_{mud} / Cap_{OH/DP}$$

5. Select P_{step}

6. Calculate V_{step} which is the volume of mud (bbls) that will exert a pressure P_{step} in the drill pipe/open hole annulus

$$V_{step} = P_{step} / Hyd_{OH/DP}$$

Accurate measurement of volumes bled back and pressures at all stages of the stripping operation is essential. Refer to the stripping sheet form and additional calculations in Section 10 sub-section 2.2.

Depending on rig design and equipment set-up, instead of bleeding off mud and gas via the MGS into the trip tank, it can also be bled off into an auxiliary calibrated tank ("stripping tank"). The returns may be taken in the trip tank and the closed end displacement of a stand of drill pipe bled into the auxiliary tank after each stand has been stripped in and the excess volume is measured in the trip tank.

B. COMMENCEMENT OF STRIPPING

1. Commence stripping. Allow the choke pressure to build up to: P_{choke} = SICP + P_{saf} + P_{step} without bleeding off any mud.

2. Once the required choke pressure is reached, P_{choke} must be kept constant while drill pipe is stripped in the hole.

   If the influx is entirely liquid (water for example), the volume of mud bled should be equal to the closed-end displacement of the stripped-in drill pipe.

If the influx is all or in part gas, the volume of mud bled should be greater than the closed-end displacement of the stripped-in drill pipe because of the gas migration/expansion. This equates to a hydrostatic pressure loss that must be compensated for by using the following procedure:

3. Continue stripping in maintaining P_{choke} constant until the total volume drained to the trip tank exceeds the closed-end displacement of the stripped-in drill pipe by V_{step}.

4. Once the measured excess volume in the trip tank equals V_{step}, the choke is closed and the choke manifold pressure (P_{choke}) is allowed to rise by P_{step} by means of stripping drill pipe in the hole.

   P_{step} should be subsequently added to the choke pressure to form a new P_{choke} each time the volume bled off exceeds the closed end displacement by V_{step}

   It is recommended to strip the complete stand in the hole for each phase of the operation (e.g. while maintaining P_{choke} constant, or when increasing P_{choke} by P_{step}) to simplify the bleeding off process and to improve the accuracy of differential volume measurements. As a result of stripping the complete stand, higher than required choke pressures will occasionally be obtained which should be taken into account when the next pressure increment is added. *For example, if it was necessary to add 50psi (i.e. P_{step} = 50psi) and stripping in a complete stand without bleeding imposed 60psi, then only 40psi should be added for the next P_{step} increment.*

5. Repeat as often as necessary, until one of the following situations arises:
   - The bit is back on bottom.
   - Gas has reached surface.
   - Stripping is no longer possible (excessive pressures, BOP stack problems, open hole resistance, etc.).
   - Should surface pressure be approaching MAASP and either there is evidence of gas migration or it is clear that the bit has entered the influx, consideration can be given to performing an intermediate circulation using the drillers method. If possible, choke pressure during such a circulation should not exceed MAASP.

6. Stripping is then stopped and the well killed conventionally, if the influx is above the bit.

The chance of having to kill the well with the bit off bottom is relatively small, since the migration rate of gas in mud is such that the bit can be stripped back to bottom before gas has reached surface.

Migration rates of gas in work over fluids are much higher and should be taken into consideration before deciding to start stripping pipe in the hole.

1.4 STRIPPING THROUGH RAM PREVENTERS

- Stripping through ram preventers must only be permitted with surface stacks.
- Stripping ram to ram must not be allowed if only two sets of ram preventers are available for use.

As in all stripping operations, the location of the tool joint in the preventer stack must be known at all times.

1. To prevent premature damage to the ram preventers, the closing operating pressure must be reduced to a minimum.
2. When a tool joint reaches the lower set of closed rams, the upper set must be closed.
3. The pressure between the rams is then brought up to the current well pressure and the lower rams are opened allowing a tool joint to pass.
4. When the next tool joint approaches the upper rams, the lower set of pipe rams are closed and the pressure between the two sets of rams is bled off and the upper rams are opened allowing a tool joint to pass.
5. This process is repeated alternating stripping through one ram then the other until the pipe reaches bottom or until the bit enters the influx.

1 PROCEDURE

Bullheading is a method used to displace an influx back into the formation without needing to bring it to surface.

This method should, in most cases, be considered only as a last resort.

2 REASONS TO CONSIDER BULLHEADING

- The influx size is too large to be circulated to the surface (i.e. excessive surface pressures and/or volume expected is too large for the surface gas handling equipment).
- A combined kick and lost returns situation is experienced (downhole annulus bullhead rates must exceed the gas migration rate to ensure the situation does not deteriorate further).
- Calculations show that casing pressure during a conventional kill operation will probably result in a detrimental well control situation (in this case, only the kick needs to be squeezed back).
- The drillstring is out of the hole or has been sheared.
- The drillstring is plugged, washed out or has parted.
- The influx is caused by swabbing when pulling out of the hole (POOH).
- The influx or drilling mud returns contain more H2S than the surface equipment can safely handle at surface.

In some instances, e.g. workovers in cased hole, H_2S wells, HP/HT wells or well testing, bullheading will be considered as the prime method. In such cases, the choice of bullheading must be stated in the well plan.

While the advantages or reasons for bullheading are given above, there are disadvantages that must be borne in mind:

- Fluid will go to the weakest formation interval and may not follow the preferred path, particularly with a long open hole section.
- Potential is created for an underground blowout.
- Even a successful bullhead may not kill the well; it may still be necessary to circulate heavier kill mud after displacing the influx back into the formation.

3 PROCEDURES

3.1 PRIOR TO BULLHEADING

- Position of the influx in the wellbore is fundamental to deciding whether to bullhead. The nearer the influx is to the formation the more likely the bullheading operation will be successful.
- Consider using the volumetric method to eliminate the complication of migrating gas. If the gas can be largely removed this way, the bullheading operation is likely to be much easier and more effective in killing the well.
- If a gas influx is suspected (shut-in pressures continue to rise indicating migrating gas), the pumping rate for bullheading must be fast enough to exceed the rate of gas migration.
- If pump pressures increase instead of decreasing, it is an indication that the pumping rate is too low to be successful. This can be a problem in large diameter holes.
- Review pressure limitations of pumping equipment, wellhead equipment and casing.
- Consideration may have to be given to using the cement pump if surface pressures are high.
- Special consideration should be given to the possibility of breaking down long open hole sections beyond the last casing shoe rather than the producing formation.
- In this event, rather than killing the well, this procedure may aggravate the development of an underground blowout that could pose risks to nearby wells in communication with the formations involved.
- It could also increase risk of a blowout around casing in place with subsequent obvious risks.
- Where possible, bullheading should be carried out through an upper choke or kill line outlet on the BOP's so that in case of washout or equipment failure, a lower outlet and preventer can be used.
- A check valve is required between the pumping unit and the well should surface equipment fail during the procedure.
- The cementing unit may be used for better control and adequate pressure rating.
- Large mud volume and LCM pills should be available in case major losses are experienced during the operation.

3.2 OPERATION

(*Refer to Section 10 Subsection 11 for example calculations.*)

1. Calculate maximum injection pressure from the leak-off value, the casing shoe and the mud weight in the hole. The maximum injection pressure must be adjusted if higher weight mud is used to bullhead.
2. Ensure equipment pressure limitations are not going to be exceeded.
3. Ensure that enough mud volume is on the surface to displace the entire open hole volume by 50% excess.
4. Establish injection pressure by pumping down the string/annulus at a slow rate. Attempt to keep a constant rate and plot the injection pressure versus the volume. Have the LOT information available so this information can be compared.
5. Continue pumping until minimum volume displaced is influx volume plus 50%. In some situations the entire open hole volume must be displaced plus a margin.
6. Shut down and observe the well. Drillpipe and annulus pressures should be approximately the same.
7. Raise mud weight (if necessary) and circulate using the Wait and Weight Method until the annulus is clear of influx and the well killed.

4 COMPLICATIONS

If unable to inject at chosen pressure, increasing it to the maximum may be necessary.

If injection is established but injection pressure begins or continues to rise, this could be due to either:

- Gas migration, in which case the injection rate must be increased to overcome the migration rate.
- The permeability of the reservoir is decreasing due to damage from the mud. Bullheading should continue until maximum surface pressure is reached and then the kill procedure re-evaluated.
- If losses are evident after completion of the bullhead or during the bullhead operation, attempts should be made to stabilize the well with loss circulation material, gunk squeezes or if necessary with cement squeeze.

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WELL KILL TECHNIQUES
OFF-BOTTOM KILL

1 GENERAL

This method involves circulation at the point of shut-in or at the point stripping has ceased prior to reaching TD. The bit will not be at bottom and the kill operation will be more complicated.

2 REASONS TO CONSIDER OFF BOTTOM KILL

An off bottom kill might be considered if:

- Casing pressure is too high to allow continued stripping.
- Heave becomes a problem.
- Pipe is stuck.
- Equipment problems arise.

3 PROCEDURE

The further off bottom and the weaker the casing seat, the more difficult this method becomes. If the casing seat is strong enough, it might be possible to kill the well by weighting up the system and pumping heavy mud.

The density of the mud used should not exceed the Equivalent Mud Weight (EMW) based on leak-off data if the bit is in open hole.

Because the bit is at a shallower depth relative to TD, the well will be "over killed" and the chances of becoming stuck are considerable. The heavier mud may not prevent gas migration.

If the well can be stabilized and the influx evacuated with this method, it will be necessary, once the well is opened up, to run into the hole (and circulate) in stages with a lighter MW.

3.1 STRING OUT OF HOLE

If the string is out of the hole when an influx is detected and the closed-in surface pressure allows safe lowering of the first stands of drill collars or drillpipe into the well, the OIM may decide to start stripping since it will improve the well control situation.

The topdrive/kelly may have to be used in conjunction with singles for extra weight. Drill Collars used should be slick.

The maximum surface pressure that can be overcome by the weight of the first stand, ignoring the friction between the annular preventer and the string, is calculated as follows:

$$\text{Max. Surface pressure} = \frac{\text{Weight of first stand in mud}}{\text{Cross-sectional area of the stand}}$$

NOTE: for subsea stacks, this will be the weight of stands from rig to BOP.

The procedure to enter the string back into the well is as follows:

1. Install an inside BOP (Gray valve or preferably, float valve) on the first stand of slick drill collars or drillpipe.
2. Use a bit without nozzles to reduce the chance of plugged nozzles.
3. Lower the stand to just above the blind/shear rams and close the annular preventer. Equalize pressure between wellbore and annular.
4. Open the blind/shear rams and strip through the annular preventer. Allow the choke pressure to increase by Pstep and maintain constant thereafter.
5. Fill the string with mud.
6. If drill collars are used instead of drillpipe, continue stripping the slick BHA and maintain a constant choke pressure. Do not use more than three stands of drill collars.
7. Allow the choke pressure to increase to SICP + Psaf + Pstep without bleeding off any mud when stripping the first stands of drillpipe.
8. Continue the combined stripping and volumetric method as described in the previous section.

If it is not possible to strip the string into the well, the volumetric method or bullheading may have to be employed.

NOTE: Re-entering a shut-in subsea well with a drillstring on a floating rig may be difficult because of the heave and the distance to the subsea BOP stack.

The heave should not exceed the distance between blind/shear rams and annular preventer.

In order to avoid buckling of the drillpipe in the riser, Drill Collar weight should be used to get the string back into the hole.

If re-entry is not possible, bullheading or a volumetric kill should be considered.

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1 PROCEDURE

It is quite likely that some gas will have accumulated under the closed BOP during displacement of the influx.

This gas must be removed from the stack before the BOP is opened. The precise procedure will vary depending on the specific rig's BOP stack-up, outlet configuration and the preventer(s) used for shutting the well in.

The volume of the trapped gas depends on the volume between the preventer in use and the choke line outlet in use.

1.1 REMOVING TRAPPED GAS FROM THE BOP

1. C & K line flush with KWM: Isolate the well with the lower rams; displace the kill line with kill weight mud taking returns up the choke line. Continue to circulate until the kill and choke lines are full of uncontaminated kill weight mud.
2. Displace choke line to water or base oil to BOP stack taking returns up the kill line. Do not over displace. If water is used consider hydrate inhibition if required.
3. Close the fail-safe valves on the kill line.
4. Vent the choke line to the MGS. This will unload the water or base oil and depressurized gas.
5. U-tube OMW in riser up choke line: Open the annular preventer and allow the mud to u-tube from the riser into the choke line. Since the fluid level in the riser will drop, continuously fill the riser with mud.
6. Choke line flush with KWM: Close the annular preventer and displace the choke line with kill weight mud through the kill line. At this point all trapped gas should have been removed from the stack.

1.2 DISPLACING THE RISER TO KWM

1. Close the diverter and line up returns down the flow line.

   Note: Where rig design permits, line up returns to flow through the MGS as an additional precaution.
2. Open the annular and displace the riser to kill weight mud.
3. Close the annular.
4. Open the pipe rams and monitor the well for flow through the choke.
5. If the well is dead, open the annular.

6. Circulate and condition the mud.

Diagrams illustrating a similar stack flush procedure are available on the intranet: http://www.rigcentral.com/hqs/pt/well_operations_group/Well_Control.asp

1 DECISION FLOW CHARTS

Figures 6.9.1, 6.9.2 and 6.9.3 are decision flow charts for on bottom, off bottom and bullhead kills, respectively.

Figure 6.9.1, On Bottom Kill (Yellow Chart)

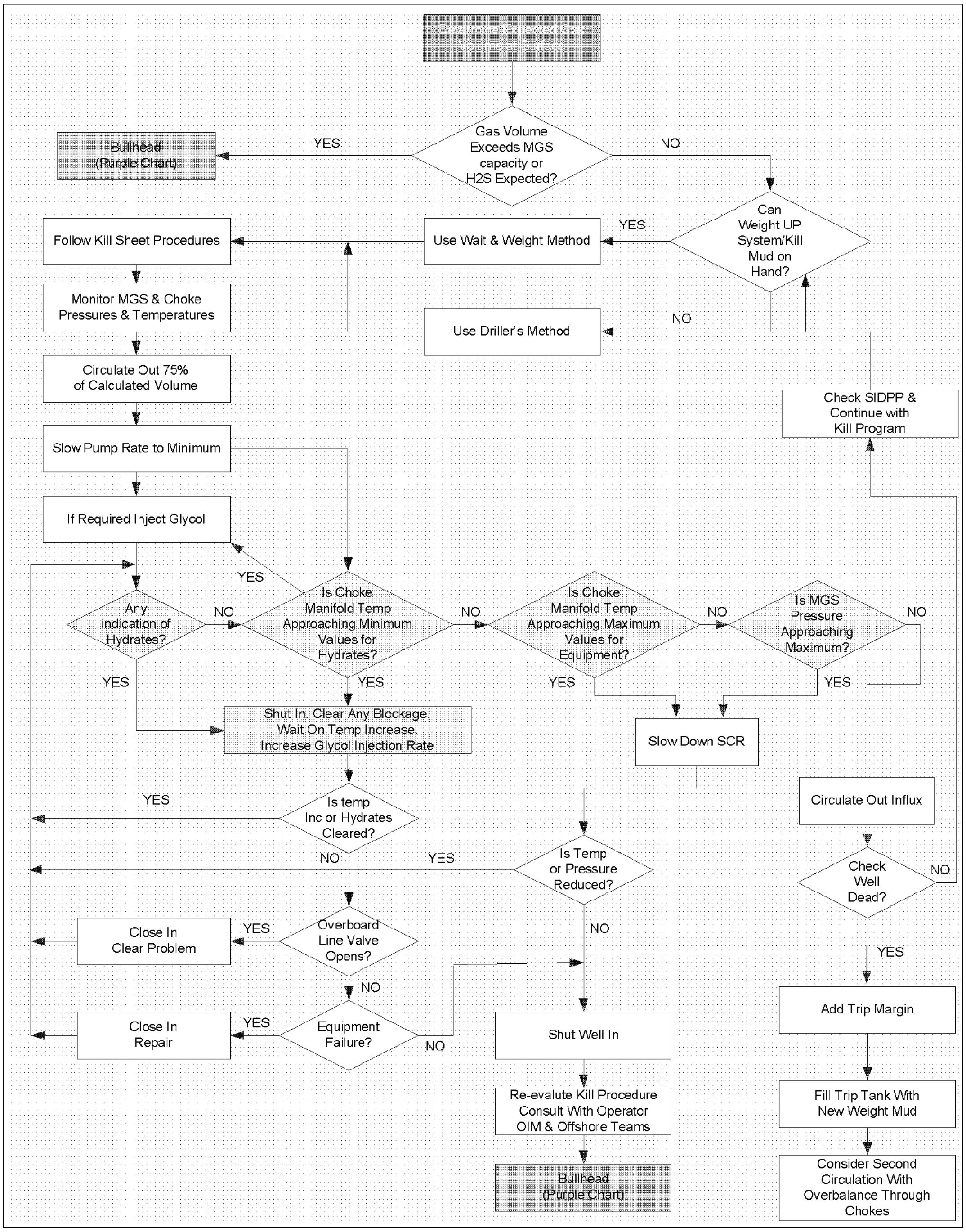


Figure 6.9.2, Off Bottom Kill (Red Chart)

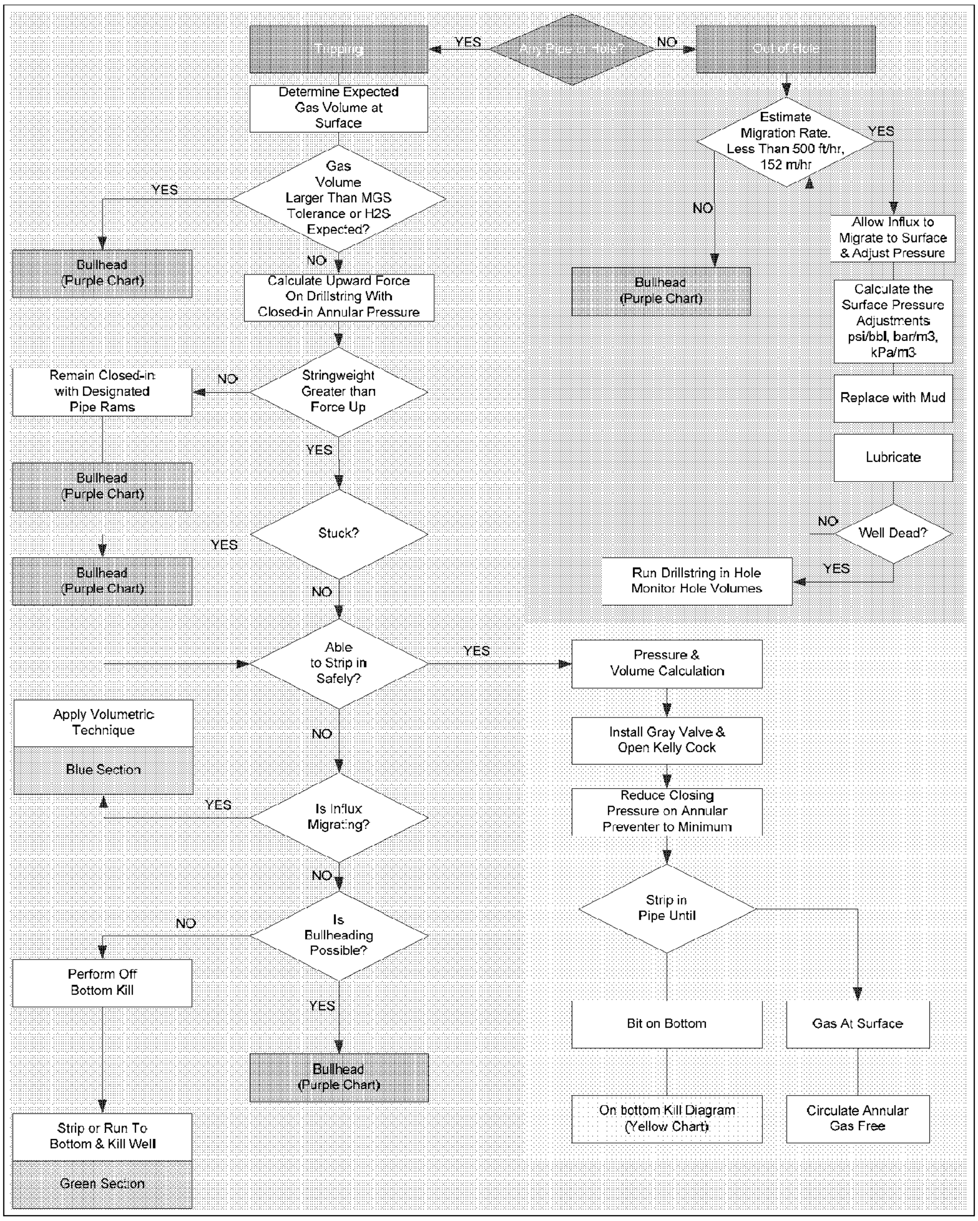
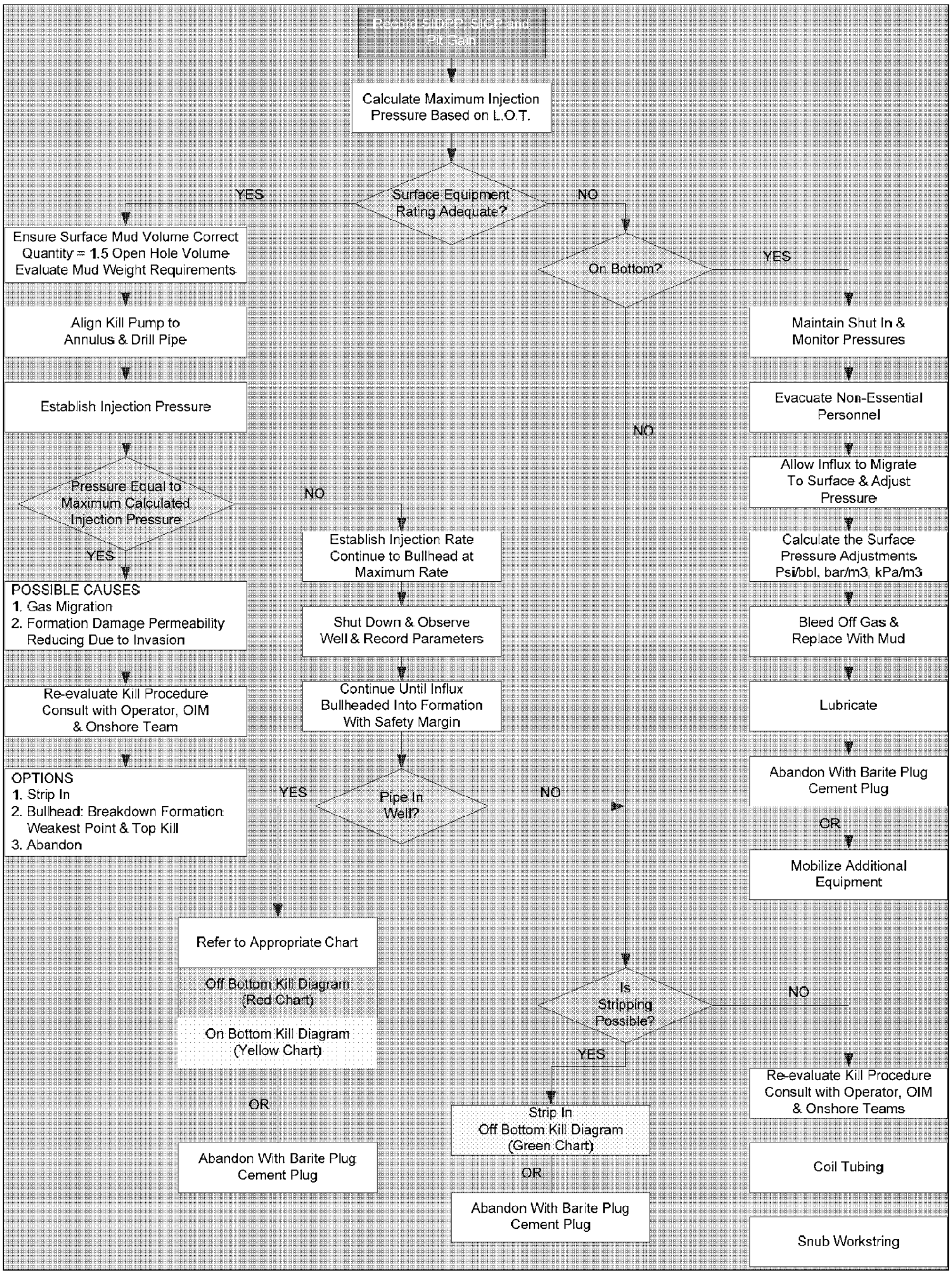


Figure 6.9.3, Bullheading Flowchart (Purple Chart)



1 GENERAL

Problems may occur during a well control situation and, depending on their nature, may have a significant impact on the operation. The principal personnel involved in the kill operation should be aware of potential problems, be able to recognize them, understand the implications and resolve them.

It should be noted that restarting a kill is a delicate operation and shutting-in the well should be avoided. However, if there is any doubt the well should be shut-in.

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2 PROBLEM SOLVING MATRIX

Problem	PRESSURE INDICATIONS Drillpipe	Casing	BHP	Other Indications	Comments
Washout in string/bit nozzle	↓	→	→	KMV back to surface earlier than expected	If washout occurs above the kick, it is unlikely that it will be possible to circulate it from the well. If the washout is identified to be below the kick, circulating out should be possible. Extended circulation through the washout will very likely result in the drillstring parting. If the washout is near the surface, stop circulation and either bullhead the kick back into the formation or implement the Volumetric method.
Plugged string/bit	↑	→	→		Do not open choke to reduce DPP as this will reduce BHP and could induce a further kick. If the increased DPP is not too high, continue the kill with the "new" DPP. If DPP approaches maximum relief valve setting, reduce pump speed while controlling choke pressure (NB, CLFL). Continue kill at lower circulating rate. If this is unsuccessful, shut-in well. If the bit becomes completely plugged the DPP will increase sharply and the CP will eventually decrease. A wireline operation should be planned to perforate as far down the string as possible.
Packed off Annulus	↑	→	↑	Decrease in returns	There is no fixed set of rules and well conditions/specific situation will determine course of action.
Washout in choke	↓	↓	↓	Gradual Choke closure to maintain pressures	Check the pit levels to confirm that partial losses are not occurring. Isolate the washed out choke and line up the back-up choke. Resume circulating by holding the choke pressure constant (less CLFL for subsea) while bringing the pumps up to kill speed.
Plugged choke	↑	↑	↑		The choke may become plugged by cutting, hydrates forming or the lead coming loose from target flanges upstream of the choke. If this occurs: Shut down the pump immediately. Isolate the plugged choke and line up to the back-up choke. Resume circulation (after bleeding off any excess pressure from the well) by holding choke pressure constant (less CLFL subsea) and bringing the pump up to kill speed.

Problem	PRESSURE INDICATIONS Drillpipe	Casing	BHP	Other Indications	Comments
Mud Pump Problems	Variable	Variable	Variable	Rotary hose vibration Pump knocking/ fluid hammer	Mud pump efficiency is very important in all well control operations and the efficiency of the mud pumps at different rates must be known. If a mud pump problem occurs: Identify cause of problem. If necessary, shut-in the well and isolate the pump. Line up the reserve mud pump. Resume circulating by holding the choke pressure constant (less CLFL for subsea) while bringing the pump up to kill speed. Repair the damaged pump immediately.
Partial Losses	↓	↓	↓	Decrease in pit level (NB: opposite effect of gas expansion + mud additions.)	During well control operations lost circulation is normally caused by induced fractures. This can happen at any time during initial shut-in or kill operation. It is important to differentiate between seepage, partial, severe and complete losses (refer to 8.8). If the mud volume can be maintained by mixing, continue killing the well in the conventional manner with the lowest, effective pump speed, maintaining drill drillpipe/BHP accordingly. Add lost circulation material to the kill mud (if possible). There is no fixed set of rules and the situation will dictate the method of cure.

↑↓ INCREASE
DECREASE
→ STAY THE SAME

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3 ADDITIONAL COMPLICATIONS

3.1 SURFACE PRESSURE APPROACHING MAASP

MAASP is calculated from the last LOT or FIT and is only valid when a full column of fluid of a known density extends from the surface to the weakest point in the open hole. It is possible that surface pressures greater than the MAASP may not actually cause formation fracturing.

During well kill operations, from the moment that the top of the kick is displaced above the open hole weak point, the MAASP becomes less critical at the shoe and focus should move to surface equipment pressure ratings.

It is a Company procedure that constant BHP, at least equal to the formation pressure, must be maintained. Priority must be given to maintaining constant BHP even if the MAASP is exceeded. However, all efforts should be made to minimize the risk of MAASP being exceeded.

If the kick is below the last casing shoe and the surface casing pressure approaches the MAASP then one of the following options could be selected:

- Reduce the circulation rate to the lowest possible and adjust the drillpipe pressure accordingly.
- Continue with kill procedures and exceed MAASP thereby risking formation breakdown.
- Bullhead the kick back into the formation.
- Use a tertiary control method (barite/cement plug).

Once the kick has passed above the casing shoe, the MAASP will be based upon the pressure ratings of the following:

- Innermost casing string.
- Wellhead equipment.
- BOP and related surface equipment.
- Other equipment exposed to burst or collapse pressure.

The Driller must be instructed in writing on what action needs to be taken if the casing pressure reaches or exceeds the MAASP immediately after initial shut-in.

3.2 STUCK PIPE

Stuck pipe during a well kill operation can cause problems, more so if it is stuck off bottom. The priority during a well control operation is to kill the well, resolving the problem of stuck pipe is secondary. If circulation is still possible then the well kill operation should be carried out using approved procedures.

If there is no circulation, and bullheading is not possible, remove the kick by the Volumetric method. In order to kill well, perforate the string above the stuck point and perform a top kill.

3.3 DAMAGE TO BOP SEALING ELEMENTS

3.3.1 ANNULAR PREVENTER

A leaking annular packer will manifest itself by requiring steadily higher pressures to effect a seal during BOP tests and is the first indication that it is worn or damaged and should be changed at the earliest opportunity.

For surface stacks, when packing unit leakage occurs during kick control, pipe ram preventers must be closed and, if necessary, a second set of ram preventers should be equipped with appropriate sized rams before the killing operation is resumed.

For subsea stacks, the upper annular preventer should be used for all exercises, shut-ins and stripping operations, leaving the lower preventer for back-up. On some installations, if the LMRP has two annulars, then the use of the lower annular would be acceptable.

3.3.2 RAM PREVENTERS

To prevent rapid deterioration of ram packers the following precautions should be observed:

- Recommended operating pressure (1500 psi) should not be exceeded (higher pressures may be required to shear pipe with shear rams).
- Never close on open hole during function tests.
- Under severe well control conditions, failure of ram packers can occur.
- On surface BOP stacks, two rams of correct size must be maintained, where possible. This may mean that the bottom ram (emergency) is closed and the upper ram packers changed before the kill operation is resumed. The OIM must decide whether to change the damaged rams or continue with the kill.

3.4 HYDRATES

Hydrates are a complex crystalline structure of hydrocarbons and water or, more simply, a frozen gas, commonly methane. Hydrates can cause severe problems by forming a plug in valves or chokes, completely blocking flow. Upstream pressure then increases which compounds the problem.

Hydrate prevention can be achieved as follows:

3.4.1 INSIDE THE WELLBORE

- Good primary well control practices to minimize gas coming from the formation.
- Reducing free water by using OBM or maximizing the chloride content of a WBM.
- Maintaining wellbore temperature as high as possible (i.e. avoid long periods of no circulation).
- Injecting methanol or glycol at a rate of 0.5-1 gal. (2-4 litre) per minute on the upstream side of a choke or line and/or down the kill line so that it mixes with the mud/gas coming up the choke line.

3.4.2 OUTSIDE THE WELLBORE

Hydrates could form on the outside of the BOP stack in deepwater wells.

Further details on hydrates are contained in the deepwater section of this manual.

3.5 LOSS OF POWER

If rig power failure occurs then shut the well in. The volumetric technique may have to be used if influx migrates while attempting to restore power. Always assess extent of power failure before deciding on whether to resume the kill using auxiliary or back up systems, e.g., cement pump

4 COMPLICATIONS ARISING FROM SPECIFIC OPERATIONS

4.1 CEMENT JOBS

Kicks that occur while cementing are the result of reducing the hydrostatic pressure during the operation. Wells have been lost due to improperly designed cement slurries and spacers.

The following can cause a reduction in hydrostatic pressure/formation breakdown subsequently leading to a kick:

- A spacer of inadequate density or too much volume is pumped ahead of the cement.
- The density of the cement slurry exceeds the formation strength, causing losses to the formation.
- If lightweight cement is used, backpressure may be held at the choke. Inadequate backpressure will result in a flow; excessive backpressure may cause lost circulation.
- As cement is setting, its effective density passes from that of the slurry to its base fluid (i.e. water) density.
- High fluid loss opposite permeable zones will cause premature dehydration of the cement slurry.
- Formation of a micro-annulus (channel) which provides a flow path for fluid/gas. This can be created by a casing pressure test once cement is set or due to the heating up of the casing as cement sets.
- Casing float failure.
- Free water, particularly in deviated wells.
- Poor cement retarder design or performance.
- Swabbing the hole while reciprocating pipe during circulation and cementing of the casing.

All of the above must be addressed in the design of any cement job where zones of potential flow are exposed. The well must be closely monitored during all phases of the cementing operation, and BOP's must not be nippled down before the cement has taken a final set and the well is confirmed static.

4.2 WIRELINE IN THE HOLE

A well kick may occur with wireline either in the hole or inside the drill string. Instructions will be given to the Driller prior to wireline operations regarding the method of shut in to use in the event of apparent well flow.

All wireline perforating operations taking place on an under-balanced well, or well with the potential to be underbalanced will be undertaken using a purpose-built lubricator that is certified and rated to handle the expected wellbore pressure and fitted with a wireline BOP.

At all times when line is run inside the drill string, a fully open safety valve should be installed and mechanical or hydraulic cutters available on the rig floor. In the event of well flow, the wireline should be cut under tension and off bottom if possible (to ensure the line will drop clear of the safety valve) and the safety valve closed before completing closure with the hard shut in method.

4.2.1 WIRELINE OPERATIONS WITHOUT PRESSURE CONTROL

Many wireline operations are conducted using drilling fluid as the primary means of pressure control with the rig BOP as secondary control. If there is a kick, the rig BOP's would be used to maintain control until the well is killed.

During logging operations:

Before any wireline operation begins, all drilling personnel must be involved in a safety briefing during which responsibilities must be clearly defined and sufficiently detailed instructions must be given to drilling personnel to enable them to close the well in under any foreseeable circumstance.

The detailed instructions from the logging vendor should include:

- The wireline displacement volumes.
- Tool string displacement volumes.
- Runs that have sampling tools that dump the sample into the annulus.

It is the responsibility of the Driller (or designee) to continuously monitor the well during logging operations. This must be done by continuous circulation over the hole using the trip tank system.

If a flow occurs notify the logging unit and:

- If time allows, pull the wireline above the BOPs and close the blind/shear rams.
- If time does not allow or safety could be compromised, the annular BOP must be closed. If possible the wireline should then be stripped out of the BOP, and pulled to the surface. It may not be possible to maintain a seal on the wireline while attempting to strip out of the hole.
- If conditions dictate the rig must be prepared cut under tension and off bottom if possible (on surface BOPs this will ensure the line will drop clear of the shear/blind rams) and the shear/blind ram closed. Mechanical or hydraulic cutters must be on the drill floor for this purpose any time line is being run.
- Shear/blind rams are to be used only as a last resort.

4.2.2 WIRELINE OPERATIONS WITH PRESSURE CONTROL

When conducting wireline operations where it has been decided to use dedicated pressure control equipment, this equipment must be capable of the following:

- The wireline cable must be compatible with the surface wireline pressure containment equipment. The wireline BOP must be capable of both forming a seal on the cable and shearing the cable. When in use, the function and operational limitations (e.g. pressure rating and stripping capability) of the stuffing box must be clearly understood.
- Providing a method of closing the well in completely when the tool string is in the riser or is being changed out.
- Closing the well in without reliance on external pressure or power sources (i.e., equipped with a failsafe shut-in system) with or without wireline in the hole.
- On surface BOPs consideration should be given to the use of a shooting nipple assembly if no tubulars are in the hole. (Refer to section 9, subsection 5, page 4 for details on shooting nipple requirements).

In addition, the following should be noted:

- The relationship of rig BOP's to the operation in progress must be kept clear to all involved.
- Wireline pressure control equipment must only be used for its designed function.
- Ensure that wireline BOP equipment is installed correctly.
- Be aware of pressure ratings and limitations of equipment in use.
- All pressure tests must be conducted using applied surface pressure (not wellbore pressure).

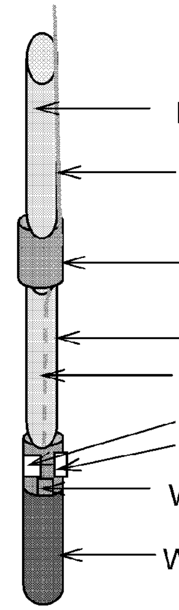
4.2.3 PIPE CONVEYED LOGGING

While running drill pipe conveyed logging the position of the side entry sub (SES) is important while considering the well control scenarios. A detailed risk assessment should be performed prior to conducting this operation.

Mostly on deepwater floaters the possibility to have the SES inside the riser is high. In case of influx the annular or pipe ram can be closed over the pipe. Though there are pack-off rubbers around the cable in the SES there is a possibility of leakage of mud at the SES during long circulating hours. The pack rubber and the flapper valve differential pressure containment should be understood.

Invariably on bottom-supported rigs' the SES will be below the BOP. The annular or pipe ram will be closed on the drill pipe and wire line cable. The force is expected to crush / damage the cable when the rams are fully closed. Consideration can also be given to cut and drop the Wireline cable before closing the rams.

Figure 7.1.1, Typical Schematic of Drill Pipe Conveyed Logging.



4.3 DST OPERATIONS

A drill stem test (DST) is a temporary well completion to gather information on the potential productivity of a formation. Since DST's involve bringing formation fluids to surface special precautions are required to maintain control of the well.

A detailed review of the relevant test program must be carried out on the rig before commencing operations to assess the risks involved. The OIM and Senior Toolpusher, in conjunction with the Operator Representative and key Service Company personnel, must review all aspects of the program.

The review should concentrate on key areas such as communication, roles and responsibilities of personnel, emergency response, expected test parameters (temperature, pressure, etc.) and any required changes to the program.

4.3.1 BASIC PRECAUTIONS

- Prior to conducting any DST the BOP's and the gas detection system must be tested.
- Drillpipe or tubing can be used but must be designed for anticipated conditions. Drillpipe must not be used as a test string or completion string in a gas well or in a well where H_2S is present. Any doubt about the test string's integrity must be referred to the Rig Manager Performance. During the test, the annulus pressure must be monitored to ensure a leak does not develop in the test string.
- All DST work must use a surface tree that enables the test string to be closed in. When wireline is to be used during the test, pressure control equipment must be installed.
- When the DST is finished, ensure that the contents of the test string are reverse circulated out to mud prior to releasing the packer (when using retrievable packers) or unstinging from permanently set packers by opening the reverse circulation valve. This valve may be pressure actuated or operated by dropping a bar or ball.
- Special attention should be emphasised for H_2S detection (refer to H2S Section).

4.3.2 SPECIAL PRECAUTIONS FOR FLOATING RIGS

- DST's on floating rigs must always be conducted with the test string landed off in the wellhead with a subsea Master Valve installed (E-Z tree or Sub Sea Test Tree).
- When it becomes necessary to pull off location due to rough seas or other emergencies, the hydraulic latch assembly is disconnected by bleeding hydraulic power pressure from the surface, leaving the well shut-in and safely under control. Ensure time required to perform this sequence is known and acceptable.
- The BOP pipe rams are closed around the slick joint situated immediately below the Master Valve thus sealing off the well annulus.
- Following emergency closure of the Master Valve and disconnection of the hydraulic operator, the blind/shear rams must be closed above the Master valve during temporary abandonment.
- Ensure enough chiksans or high pressure flexible lines are used to allow compensation for the maximum heave.

4.3.3 PRECAUTIONS WHILE TESTING

- Review Field Operations Manual for Well Testing Policy and Procedures
- For the initial test of a zone, DST tools must not be opened at night without the permission of the Operations Manager Performance. The SVP of the Business unit will determine if this decision will be made at the Unit or Division level.
- When testing wells containing H_2S, NO GAS should be released into the atmosphere unless it is burned on the spot.
- Always open up a well slowly, using an adjustable choke.
- An emergency surface shut-down system (ESD) should be incorporated in any well test hook-up.
- Always pressure test the installed equipment, prior to opening up the well.
- The spacing between the various units comprising a well test hook-up should be implemented as per the recommended safety standards.
- Wind direction should be considered when venting gas into the atmosphere. Total lack of wind may create hazardous conditions.
- Minimize risk of ignition by grounding units, not allowing naked lights/hot work, etc.

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1 DROPPING THE DRILLSTRING

A quick decision may have to be made by the Driller to drop the drillstring. The outcome of this "last resort" depends on the severity of the kick and the speed of execution of the correct procedure.

Situations that may require the drillstring to be released include:

- If an internal blowout occurs and the shear rams cannot be used.
- If an internal blowout occurs when the drill collars are across the BOP.
- As an alternative to the use of shear rams in the event of an internal blowout when drillpipe is in the stack.
- If the BOP develops a leak and no back-up is available.

It is important to be sure that the string will clear the BOP once it has been dropped (especially on a floating rig in deepwater).

1.1 RECOMMENDED PRACTICE FOR DROPPING DRILLSTRING

1. If the topdrive is connected, pick up the string as far as possible to position a tool joint three feet above the rotary table height.
2. Stop circulating. Set the slips and break the connection three times.
3. Pick up on the drillstring and remove the slips.
4. RIH until the tool joint is as far below the rotary table as possible.
5. Select reverse on the topdrive, set the torque limiter to maximum and turn the topdrive at maximum RPM until the string separates.
6. If this operation has to be carried out while tripping, and after following the above procedure the string has not parted, consideration should be given to using the annular BOP to hold the lower section of the drillstring.

1.2 RECOMMENDED PRACTICE FOR DROPPING DRILL COLLARS

1. Position the elevators (manual) near the rotary table and attach an air hoist to the latch. If air-operated elevators are in use, position so that at least one joint (but less than two) is above the rotary table.
2. Close the annular preventer with 1500 psi closing pressure to support the string weight. Where possible, consider closing both annulars.
3. Unlatch/open the elevators.

4. Open the annular preventer(s) and release the drill collars.
5. Close the blind/shear rams, after string has had time to clear the BOP's.
6. Read and record shut-in pressure and pit gain.
7. Great care should be taken to ensure safety of personnel during these operations.

2 SHEARING THE DRILLSTRING

Blind shear rams (BSR's) can be used to cut drillpipe and then act as blind rams in order to isolate the well.

Shearing the pipe is an operation that should be conducted only in exceptional circumstances and can be considered in the following situations:

- In preference to dropping the pipe in the event of an internal blowout.
- When it becomes necessary to move a floating rig off location at short notice.

When there is no pipe in the hole, the BSR's may be used as blind rams.

Most BSR's are designed to shear effectively only on the body of the drillpipe. Procedures for the use of BSR's must therefore ensure that there is no tool joint opposite the ram prior to shearing.

NOTE: Some subsea BOP stacks have insufficient clearance between the upper pipe rams and the BSR to hang-off on the upper rams and shear the tube of the pipe.

Rig personnel must know the capabilities (i.e. what size and grade of pipe can be sheared) and operating parameters of the shear rams installed in the rig's BOP stack.

Optimum shearing characteristics are obtained when the pipe is stationary and under tension. It is recommended that the string weight be partially hung off prior to shearing. Hanging off the pipe also ensures that there is no tool joint opposite the shear rams. Maximum operating pressure should be used to shear the pipe.

2.1 RECOMMENDED PRACTICE

1. Space-out to ensure that there is no tool joint opposite the shear rams.
2. Close the hang-off rams and hang-off the string.

3. Ensure that the pipe above the hang-off rams remains in tension.
4. Close the shear rams at maximum accumulator pressure.
5. Monitor the well.

3 DISCONNECTING LMRP

There are several situations that could arise during well control operations that may require disconnecting the LMRP and moving off the well:

- If high annulus pressures approach the rated working pressure of the BOP's or because of equipment failure.
- Vessel movement due to adverse weather conditions (anchor chain or DP failure).
- Impending vessel collision or fire.

3.1 BULLHEAD AND EMERGENCY DISCONNECT

- Attempt to bullhead the kick back into the formation.
- If a drop in dart sub is in use, pump down (with kill mud, if available) the dart until it lands in the dart sub, while controlling annulus pressures.
- After the dart seats, bleed off drillpipe pressure and observe to see if dart is holding pressure.
- If the dart is holding pressure, close and lock lower pipe rams – assuming string is already hung off on designated hang-off pipe rams.
- Displace riser with sea water.
- Close all fail-safe valves.
- Shear pipe and lock the shear rams.
- Disconnect lower marine riser package.
- Slack off guide line tensioners, where applicable.
- Move rig off location.

3.2 EMERGENCY DISCONNECT (NO BULLHEAD)

- Stop the well control operation.
- Stop pumping.
- Close all fail-safe valves.
- Close and lock lower pipe rams (assuming string is already hung off on the designated hang-off rams).
- Shear pipe and lock the shear rams.

- Disconnect lower marine riser package.
- Slack off the guidelines, if applicable, and move rig off location.

4 RECONNECTION FOLLOWING EMERGENCY DISCONNECT

- Move rig back to well site. Run and latch LMRP. Displace riser with kill mud and pressure test choke and kill lines. Do not use any preventers for well control operations until tested.
- Open kill line fail-safe valves and observe drillpipe pressure (there will be no pressure if dart is holding). If pressure is observed, either the dart is not holding (though kill procedures can continue) or consider the possibility that the string has been dropped. If this is the case, the choke and kill line pressures would be the same and the only well control options would involve the use of the Volumetric method or bullheading to kill the well.
- Open choke line fail-safe valves below lower pipe rams and observe casing pressure.
- Pump down kill line to ensure that circulation through dart is possible. Observe pressure increase on choke line gauge.
- If circulation is possible then continue to kill well using kill line gauge as drillpipe pressure and choke line gauge as casing pressure.

Be sure to re-establish circulating pressures as previous slow circulating rate figures will no longer apply.

- If circulation is impossible then consider bullheading or the Volumetric method.

5 BLOWOUT/UNDERGROUND BLOWOUT

Contingency planning must be prepared on the following basis:

Stage 1 - Early Response: Pre-determined operations that can be implemented regardless of the type of blowout, including preparations for abandoning the installation and mobilizing emergency/support services.

Stage 2 - Containment: Operations designed to reduce the maximum possible damage, most of which occurs during the first 1-2 hours and depends on the type and severity of the blowout.

Stage 3 - Control: Requires the assistance of specialists and may involve some of the following services and disciplines:

- Well capping.
- Relief well planning.
- HP pumping vessels/equipment.
- Logistics.
- Operations support/contractor personnel.
- Pollution control.
- News/media interface.
- Regulatory authority interface.
- Insurance adjusters.

An underground blowout occurs when formation fluids flow from one subsurface zone to another.

The majority of underground blowouts have been the result of fracturing a shallower, weaker zone when shutting in on a kick originating from a deeper, more highly pressured zone.

If an underground flow is confirmed, the Operator Representative and the Rig Manager Performance must be notified immediately.

The direction of flow is important when choosing a control procedure.

5.1 FLOW TO A FRACTURE ABOVE A HIGH PRESSURE ZONE

Figure 7.2.1. shows a decision tree for identifying and dealing with an underground blowout of this type. If an underground blowout is suspected, no attempt should be made to control the well using standard techniques. If the annulus is opened, reservoir fluids will be allowed to flow up the well to surface, thereby increasing surface pressures.

5.2 FLOW TO A FRACTURE/LOSS ZONE BELOW A HIGH PRESSURE ZONE

Flow down the wellbore from a high-pressure zone usually occurs when drilling into a naturally fractured, cavernous or structurally weak formation. The resultant losses reduce the hydrostatic head of the drilling fluid to such an extent that a permeable zone higher in the wellbore begins to flow.

When the well is shut-in, it is unlikely that any pressure will be recorded on either the drillpipe or the casing, although the casing pressure may increase if gas migrates up the annulus. Pumping mud down the annulus will prevent this rise in pressure.

Figure 7.2.2. shows the decision tree for identifying and dealing with an underground blowout of this type.

5.3 RECOGNIZING AN UNDERGROUND FLOW

Indicators of underground flow

- Loss of returns and erratic increases in annulus pressures while circulating out a kick as the mud in the annulus is lost to a fracture zone and replaced by more influx.
- After shutting in the well, the build up of SIDPP and SICP will be interrupted by a sudden reduction in both as the formation fractures.
- Unstable or fluctuating SIDPP and SICP may result from the unsteady flow from one or more formations or from the fractured formation opening or closing in response to the changing pressures.
- In most cases, there will be little or no communication between the drillpipe and annulus. SIDPP may change without being reflected by the SICP and vice versa.
- Both SIDPP and SICP may fluctuate simultaneously or independently of each other.
- If the formation collapses around the drillstring the SICP may stabilize while the SIDPP continues to change.
- SIDPP may be greater than the SICP as a result of formation fluids entering the drillpipe.
- SIDPP may fall or go on vacuum if the mud U-tubes from the string and is not replaced by influx.
- Perform a test to confirm whether or not the shut in well is a closed system. Pump a small amount of fluid down the drillpipe and if the DPP and SICP increase, the open hole is intact. If neither the DPP nor the SICP increase then a fracture exists in the open hole.

5.4 KILL METHODS

The monitoring and recording of the initial drillpipe and casing pressures is important for selecting a method of killing the well. Although the drillpipe pressures may not provide a reading with which to accurately determine bottom hole pressure, they could indicate the minimum pressure required to control the kick (i.e. the maximum SIDPP seen prior to the formation breaking down would be used to calculate the minimum kill mud weight).

5.4.1 FLOW TO A FRACTURE ABOVE A HIGH PRESSURE ZONE

If readily available, consider running a temperature/noise log through the drillstring in order to locate the loss zone.

A. Heavy Pill

- Calculate the minimum pressure required to control the kick using the highest SIDPP recorded.
- Select a range of densities for a heavy pill that, in combination with the existing mud weight, will provide the equivalent of the minimum hydrostatic pressure to control the kick.
- Calculate the height the pill will occupy in the annulus, convert it to a volume and mix three times the required amount to account for out of gauge hole and influx cutting.
- Displace (with the choke closed) the heavy pill down the pipe and into the annulus at as fast a rate as possible to reduce contamination by the influx.
- The original mud in the annulus must be conditioned to a density that will control the formation pressure at bottom and the heavy pill used to kill the well must be circulated out in stages in order to avoid re-fracturing the formation.
- Once the well is killed and losses have ceased, POOH and cement the fractured zone.

B. Barite Plugs

If the losses continue, spot a Barite plug on bottom of at least 500ft (150m) high and 3 ppg (360kg/ m^3, 0.36kg/l) heavier than current mud weight .

- The high density/fine particle size of Barite, when mixed with fresh water containing no suspension agent, enables the Barite to settle out rapidly when pumping ceases to form an impenetrable barrier that seals off the flowing zone.
- The surface mixing facilities and plug placement must be continuous and rapid. If mixing or pumping is halted for even a short time, settling in the pits or plugging of the drillstring will occur.
- Barite plugs have the following advantages:
- They can be pumped through the bit and offer a reasonable chance of recovering the drillstring.
- The plug can be drilled easily if required.

Barite - Fresh Water Slurry Recipe (for 1 bbl/0.16 m^3):

Required Density	Volume of Fresh Water	Weight of Barite
18 ppg (2.15 kg/l)	0.642 bbls (0.102 m^3)	530 lbs (240 kg)
20 ppg (2.40 kg/l)	0.560 bbls (0.089 m^3)	643 lbs (292 kg)
21 ppg (2.51 kg/l)	0.528 bbls (0.084 m^3)	695 lbs (315 kg)
22 ppg (2.63 kg/l)	0.490 bbls (0.078 m^3)	750 lbs (340 kg)

A complex phosphate, such as sodium acid pyrophosphate (SAPP) or sodium hexametaphosphate, should be added to act as a thinner in case of contamination by mud in the annulus or by low quality barite. The concentration required is 0.7 ppb (2 kg/m^3).

NOTE: Complex phosphates will thermally degrade if the down hole temperature exceeds 140°F (60°C). If this is the case, a mixture of lignosulphonate 0.4 ppb (1.14 kg/m^3) and caustic soda 0.25 ppb (0.71 kg/m^3) can be used instead.

Optimum barite settling is achieved by adjusting the pH to 8-10 with 0.25 ppb (0.71 kg/m^3) of caustic soda.

Barite - Diesel Oil Slurry Recipe (for 1 bbl/0.16 m^3):

(A barite plug derived from a barite - diesel oil slurry is preferred in oil based or invert emulsion muds. A barite - fresh water slurry can be used provided there is a diesel oil spacer ahead of and behind the slurry.)

Required Density	Volume of Diesel	Weight of Barite
18 ppg (2.15 kg/l)	0.610 bbls (0.097 m^3)	572 lbs (259 kg)
20 ppg (2.40 kg/l)	0.541 bbls (0.086 m^3)	679 lbs (308 kg)
21 ppg (2.51 kg/l)	0.503 bbls (0.080 m^3)	730 lbs (331 kg)
22 ppg (2.63 kg/l)	0.471 bbls (0.075 m^3)	781 lbs (354 kg)

An oil wetting agent is added to increase the settling rate at a concentration of 5.0 ppb (14.0 kg/ m^3).

5.4.2 FLOW TO A FRACTURE/LOSS ZONE BELOW A HIGH PRESSURE ZONE

If readily available, consider running a temperature/noise log through the drillpipe to locate the loss zone.

- Keep pumping seawater down the annulus until a suitable LCM pill, polymer plug, cement slurry, or diesel-bentonite plug has been prepared.
- Mix and spot a diesel-bentonite 'gunk' plug (diesel, 400 ppb bentonite, 15 ppb of LCM) equal to or greater than the hole volume below the loss zone.
  - At a depth 100 ft (30 m) above the loss zone, pump 5 bbls (0.8 m^3) of diesel ahead of and behind the plug.
  - When the plug begins to exit the drillstring, close the annular preventer and pump mud into the annulus at 2 bbls/min (300 l/min) while displacing the plug at 4 bbls/min (600 l/min).
  - Once 50% of the plug has been displaced from the string, reduce the pump rates to 1 bbl/min (150 l/min) down the annulus and 2 bbls/min (300 l/min) down the drillstring.
  - Once 75% of the plug has been displaced from the string attempt a 'hesitation squeeze' with 100-500 psi (690-3450 kPa, 6.9-34.5 bar) surface pressure.
  - Under displace plug by 1 bbl, POOH, and allow plug 8-10 hours to set.
- Other Alternatives

Cement loss zone (Refer to Section 8 Subsection 8 Item 6.4, Balanced Plug).

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Figure 7.2.1, Decision Analysis for Flow to a Fracture or Loss Zone

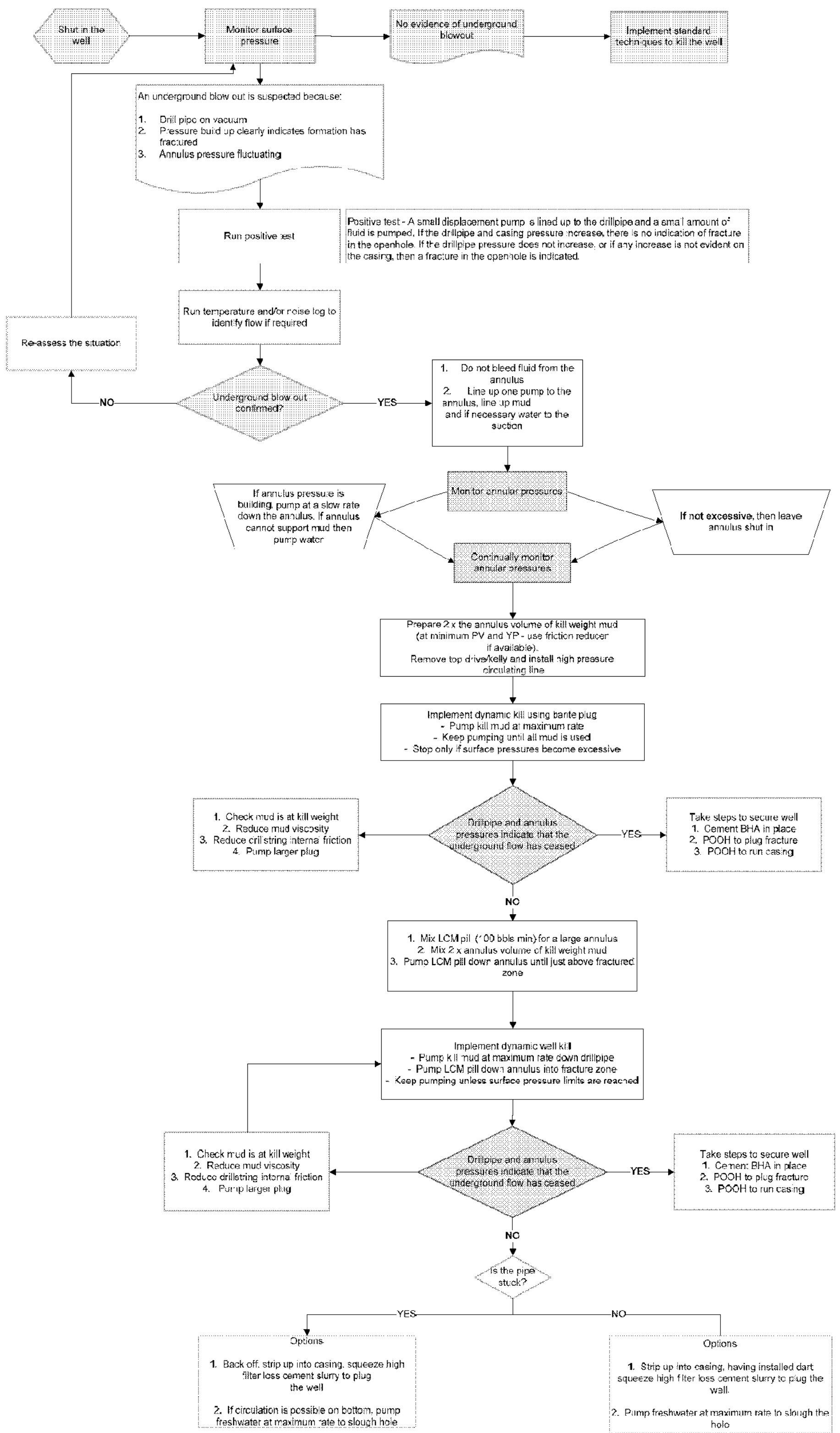
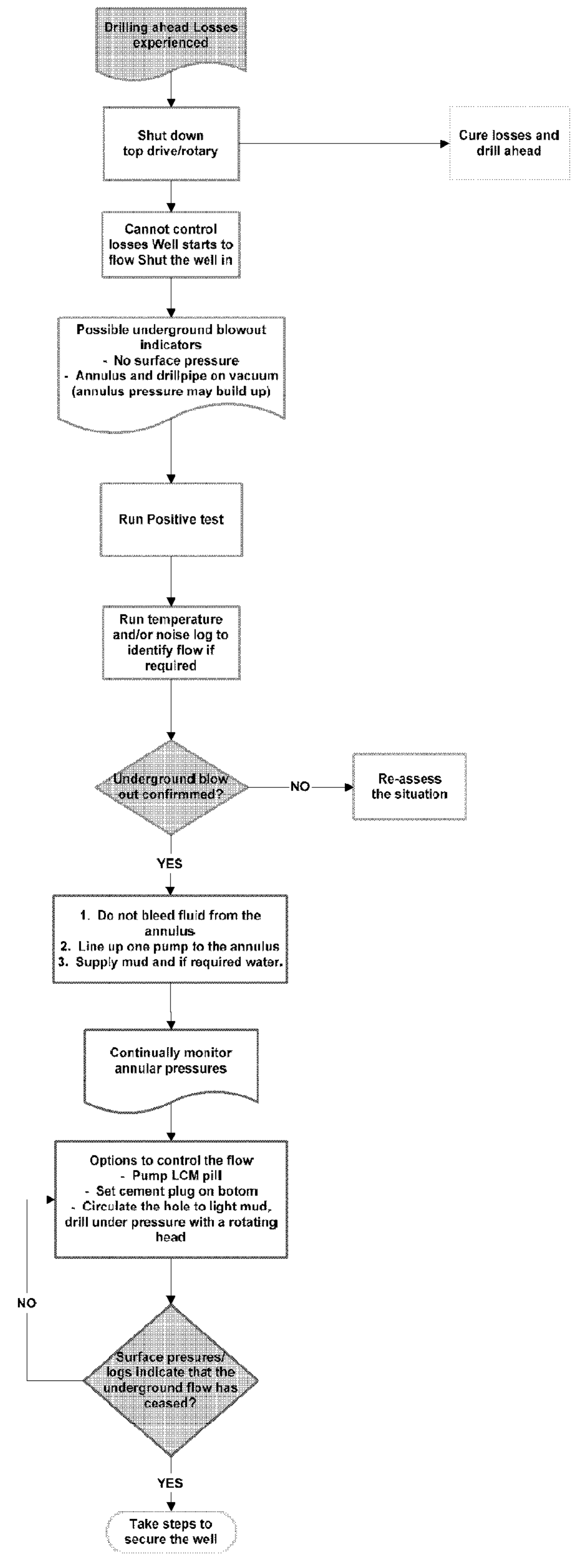


Figure 7.2.2, Decision Analysis for Flow to a Fracture or Loss Zone Below a High Pressure Zone



1 GENERAL

Statistically, shallow gas is the most likely single cause of kicks leading to blowouts.

The policy of Transocean is to ensure that the safety of all persons on board, protection of the environment, and the security of the rig are maintained as the highest priorities. It is recognized that shallow gas blowouts pose a greater risk to personnel than any other type of incident, as there is unlikely to be any significant warning time. The primary means of minimizing the probability of such events is to undertake a proper formalized planning program with the well site operator at the beginning of a contract.

2 DEFINITION

Shallow gas is considered to be any gas accumulation encountered during drilling at a depth above the setting point of the first string of casing intended for, or capable of, pressure containment. Shallow gas generally occurs as normally pressured accumulations in shallow sedimentary formations with high porosities and high permeabilities.

'Structural' overpressures may exist where the sands are relatively thick or tilted and can require higher mud weights even though they are not abnormally pressured. The degree of overpressure is determined by the ratio of sand thickness to depth and so shallow, thick sands will require higher mud weights than deeper, thinner sands.

Drilling through such a gas bearing formation requires extreme caution. Because of the difficulty in early detection of an influx while drilling top hole sections and the shallow nature of the hole, the gas, upon entering the wellbore, expands and reaches the surface very rapidly and with little warning.

It may be decided to either shut-in the well or divert, if shut-in pressures combined with the hydrostatic pressure of the drilling fluid could result in breaking down the formation and lead to broaching. In these situations, Bottom Supported Units and Barges should divert. Floating Units should always shut in the well with the subsea BOP's as broaching is a lesser concern (though consideration of gas plumes should be evaluated for shallow water floating vessels in regards to broaching).

Drillers must be instructed in writing on the specific action to take in such cases.

A copy of the procedure must be prominently posted near the BOP/Diverter control panels.

3 PLANNING AND ASSESSMENT OF RISK

Prior to starting drilling operations, the Rig Manager Performance must discuss with the Operator the assessment of 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 well plan. This determines the well trajectory, mud system, setting depths for casing strings, casing design specifications, bottom hole target and drilling philosophy needed to avoid potential hole problems. The well or drilling program describes the methodology to be applied in achieving the design parameters in the safest and most economical fashion.

As a result, every endeavor is applied to avoiding high risk areas (i.e., shallow gas pockets occurring between 500 - 2,000 ft. well depth) since these cannot normally be adequately isolated by casing. The conductor or drive pipe only provides initial hole support close to the surface and usually varies in length from about 30 to 300 ft. This pipe may be driven in or a hole drilled and the pipe cemented in place.

If drilling is to be undertaken in a region where shallow gas can occur then the operation has to involve limitations on the drilling methodology and focus on emergency contingency planning.

A contingency plan shall be put in place reflecting the method of well control to be used and defining the security measures for the unit (e.g., kick detection and move-off, etc.). Such aspects shall be discussed in detail between the operator and drilling contractor. Meetings shall then be held with all relevant crew members and third parties and these measures reinforced via shallow gas drills, to ensure an understanding and high state of readiness by all those involved in the operation. It is essential that all drilling and supporting personnel from other departments are trained to rapidly respond to emergency situations and good reaction times are extremely important.

Specific 'shallow gas' pre-spud meetings with all concerned must take place. All contingencies must be covered and mutually agreed and written up for distribution prior to spud.

3.1 LOCATIONS WHERE SHALLOW GAS MAY OCCUR

Wells with an increased risk of encountering shallow gas are summarized as follows:

- Exploration wells in general.
- Wells drilled in shallow gas prone areas.
- Wells with probable/possible shallow gas identified by a preliminary shallow gas investigation.
- Wells drilled in developed fields where charged shallow sand could occur due to poorly cemented casing strings.

3.2 EVALUATION OF SHALLOW GAS RISK

A shallow seismic survey is one of the best methods available today and is often carried out offshore to identify possible shallow gas accumulations. The reliability of such a survey varies depending on the methods of data acquisition, processing and interpretation.

Such survey work shall be conducted in accordance with accepted industry standards which covers the following objectives:

1. To identify potential drilling hazards such as shallow gas.
2. To identify and locate a suitable location for the type of drilling unit intended to undertake the well.
3. Mapping of the bathymetry (water depth).
4. Mapping of the seabed to identify possible debris and mud slides that could be hazardous to spudding the well.
5. To identify potential drilling problems such as boulder-beds and buried channels that could lead to well circulation and casing setting problems
6. To determine soil conditions at and below the seabed, to establish anchoring conditions (semi's), the potential maximum leg penetration to be expected (jack-ups, fixed platforms), what seabed support will be given to subsea fixtures such as guide-bases, etc., and how seabed conditions such as moving sands, scouring and silting up will effect those fixtures.
7. Use of detailed high resolution seismic surveys as well as conventional seismic data helps to identify potential gas bearing zones at shallow depths by using a technique known as "bright spot" analysis. The high resolution seismic data is acquired over a survey grid with a typical 500 ft. between seismic lines, the grid covering an area of several square kilometers around a proposed well location. The collected data is processed to produce detailed shallow seismic sections.

The flow chart shown in Section 10 Subsection 6 can be used as a guideline to evaluate if proper seismic equipment and techniques are employed by the Operator.

The results of such a survey can be considered as a guide, but should never be considered as a guarantee against the presence of shallow gas.

Other techniques which could be used to evaluate shallow gas accumulations are soil sampling or pre-spud pilot hole drilling, as well as evaluation of any available offset well data.

3.3 WELL DESIGN

3.3.1 DRILLING SITE AND WELL COURSE SELECTION

When the survey indicates a possible shallow gas accumulation, consideration should be given to repositioning the location, if at all possible, so as to avoid such hazards.

3.3.2 CASING SEAT SELECTION

A string of casing should be set and properly cemented in the first formation that provides an impermeable seal, even if this requires an additional or contingent string of casing.

On offshore rigs, such a string would provide the ability to shut-in a well at shallow depths without risk of broaching around the wellhead or mudline.

3.3.3 PILOT HOLE

A pilot hole, normally 9-7/8" / 250 mm or less, should be drilled, to casing point and then opened up to the required diameter, in all areas with possible shallow gas. This will improve the capability of controlling a shallow gas kick with a dynamic kill operation.

3.4 SHALLOW GAS PLAN

A shallow gas plan specific to the rig/well must be prepared in conjunction with the Operator and must conform to Company Policy. Special consideration must be given to the following, non-exhaustive, list of items:

- Crew positions and their specific duties, as listed in Section 1, must be reviewed.
- Training sessions and diverter drills must be designed around the procedure outlined in Section 4. Drills must be held by each crew at the beginning of each tour during this drilling phase to familiarize all personnel with the appropriate and immediate actions in case of a shallow gas kick.
- One of these drills, conducted prior to drilling, must include mustering crew and simulation of procedures necessary to disconnect/move off location (floating rigs only).
- Evacuation plans for all non-essential personnel must be prepared.
- Emergency power shut-down procedures must be prepared.
- Disconnecting and/or moving off location procedures for floating rigs must be prepared.

3.5 JACK-UP CONSIDERATIONS

Shallow gas reservoirs are potentially much more hazardous when penetrated from a jack-up for the following reasons:

- The conductor extends almost to the drill floor allowing the products of a kick to be discharged directly into a hazardous area. It is not practical to close the well in since the conductor pipe shoe is generally not at sufficient depth to offer appropriate containment integrity (nominal 500 psi) and gas broaching to the seabed would occur. In this event there is a real risk that the seabed becomes fluidized, thus inducing a reduction in spud can foundation and the possibility of rig movement and capsize.
- Inability to move off location.
- A hazardous situation is created if a restriction forms in the diverter line. The subsequent build up may cause gas to broach around the casing to the seabed. In this event there is a risk that the seabed becomes fluidized, inducing a sudden reduction in spudcan resistance.

Monitor the sea for evidence of gas breaking through the outside of the conductor.

The principal cause of diverter system failure, from recent industry studies, has been the malfunction of valves (slow response or blockage) and erosion of internal surfaces of the discharge route. The erosion rate in current system designs may be of the order of 1-2 mm per minute at critical bends or restrictions. Therefore these systems cannot be expected to withstand a shallow gas kick diversion for a lengthy time period and are only intended to provide time for rig evacuation.

In terms of risk reduction strategy the diverter system can only be regarded as a mitigation measure. There are effectively no means of controlling a shallow gas hazard from a jack-up and in order to reduce risk to as low as reasonably practicable (ALARP), the emphasis is placed on prevention. Transocean's rationale in dealing with this hazard is thus to avoid contact with potential gas bearing zones at shallow depths as a primary objective which is reinforced by a high state of alert and rapid response to this threat, during top hole drilling, in order to expedite the evacuation process.

3.6 RISERLESS FLOATING UNIT CONSIDERATIONS

FLOATING RIGS ARE, IN THE MAIN, SAFER THAN BOTTOM SUPPORTED RIGS for dealing with shallow gas and therefore should be used wherever possible on locations with a potential for shallow gas. It is generally considered safer to drill riserless from a floating unit.

A gas blowout in open water produces a 10° cone of low density water and a discharge of highly flammable gas. The intensity of the blowout depends to a large extent on the water depth and current.

Current further disperses and displaces the plume away from the rig. Within the plume of expanding gas, a floating vessel may suffer some loss of stability; however, the effect on a semi-submersible at operating draft would be negligible. The eruption of gas would tend to displace a vessel, and if constrained by its mooring, may cause a floating unit to heel towards the plume, thereby reducing its freeboard further.

Gas reaching sea level may catch fire and cause explosions, the result of which could cause structural failure leading to vessel instability. Procedures must be in place to shut down all non-essential equipment, ventilation systems and any sources of ignition. If a vessel is to be moved off location, then weather conditions must be monitored continuously to ensure rig is moved upwind.

Having the ability to move off location is a major advantage of floating rigs. Procedures must be in place to ensure timely movement. Many factors affect a rig's ability to move including:

- Rig type.
- Water depth.
- Riser in place or riserless.
- Disconnecting the drill string

Full consideration must be given to setting up procedures to move off location and personnel should be made fully aware of them.

The rig should be moored with the length of moorings remaining in the locker to allow the rig to be moved 400 ft (122 m) away from the plume without power. If practical, the windlasses should be held on their brakes and the chain stoppers only applied after surface casing has been set.

4 CAUSES OF KICKS

The margin of overbalance is particularly critical when drilling at shallow depths.

The amount of overbalance (expressed as a pressure) for a given margin of overbalance (expressed as a mud density) increases in proportion to depth.

4.1 GAS CUTTING

Gas cutting in the deeper sections of a well does not usually cause significant problems. At shallow depths, however, the combination of large hole size, high ROP's and high permeabilities and porosities serves to increase the volume of gas released from the formation as it is penetrated. If the overbalance provided by the drilling fluid is small (see above) the reduction in bottom hole pressure due to gas cutting may be sufficient to cause the well to kick, particularly from sands further up the hole. (Refer to Section 4 Subsection 4 Item 4)

4.2 SWABBING

It is not uncommon for BHAs to 'ball up' when drilling top hole and with a small margin of overbalance the effect of swabbing is more likely to induce a kick.

4.3 LOST CIRCULATION

High ROPs combined with low annular velocities may create a build up of cuttings in the hole. Since fracture gradients are low in these shallow, unconsolidated formations, the increase in the equivalent mud weight due to the cuttings may be sufficient to cause losses to the formation and the resulting reduction in hydrostatic pressure could cause a gas bearing sand to flow.

Lost circulation can also be caused when running casing (due to surge pressures) or during cementing the casing if slurry densities and/or circulating pressures exceed the formation strength.

5 PREPARATION AND PREVENTION

Procedures for specific top hole drilling operations to maintain primary well control must be strictly followed at all times in order to prevent shallow gas incidents.

5.1 HEAVY MUD

A recommendation of contingency mud volume must be made at the planning stage and will depend on both well and rig specifics. As a guide:

- Reserve of heavy mud for a shallow gas kill will be 1-2 ppg (120-240 kg/m^3, 0.12-0.24 kg/l) heavier than the mud weight being used.
- A minimum volume is the calculated annular volume for the section TD.

5.2 CONTROLLED DRILLING RATES

The penetration rate should be controlled to prevent excessive build up of solids which could cause fracturing of the formation and result in lost circulation.

It is also necessary to prevent accumulation of gas in the annulus which could induce the well to flow.

Caution should be used while flushing cuttings from the annulus due to the resulting reduction in annular hydrostatic fluid density.

5.3 TRIPPING PROCEUDURES

Clear tripping procedures must be available and strictly adhered to. Swabbing must be prevented while tripping out of hole. If necessary the drillstring should be pumped out to help limit swabbing.

Consideration should be given to the use of an under-reamer instead of a hole opener, as the former can be collapsed before tripping to reduce swabbing while pulling out of hole. (Refer to Section 4 Subsection 4 Item 1)

5.4 FLOW CHECKS

Flow checks must be made every time a problem is suspected. Each connection must be systematically flow checked while drilling in potential shallow gas zones.

It may be prudent to flow check every 30 ft (9 m) in order to minimize the amount of any gas bearing sand penetrated.

5.5 MUD LOSSES

Losses should be avoided. If losses are encountered they should be cured before drilling ahead unless under known conditions and with the approval of the Operations Manager Performance.

Large (or no) bit nozzles should be used to allow pumping of LCM and to permit high flow rates should diverting be required.

5.6 PWD/LWD/MWD

Use of PWD/LWD/MWD tools are an effective method of detecting the presence of gas bearing formations while drilling is in progress.

However, their usefulness is dependent on how far behind the bit these tools are located.

5.7 MONITORING ACTIVE MUD SYSTEM

The mud pit volume and mud density must be continuously monitored.

All measuring instruments must be calibrated and in good condition to detect any change in active volume. The most reliable indicator generally remains the flow out sensor.

If there is any inadequacy in the measuring instruments, extra personnel must be assigned to ensure adequate monitoring of mud volumes.

5.8 PREPARATIONS PRIOR TO DRILLING

Use the following check list:

- Test all gas detectors and alarms.
- At least one windsock must be installed in a prominent position visible from the muster point.
- Hold safety meetings with essential personnel and explain plans and procedures.
- A non ported float valve must be run to prevent sudden flow up the drillstring.
- For floating rigs, to observe for gas, the subsea camera or an ROV must be positioned so that returns can be monitored at the seabed. In addition, a watch must be posted in the moonpool area.

- All non-essential watertight doors and hatches shall be secured to prevent invasion of voids by inflammable gas.
- All fire monitors, deluge and sprinkler systems should be checked and lined up. The fire pumps and fire main systems shall be tested and the operation verified.
- Use Sea Water and ballast suction on up-current side of rig.
- Work boat activity shall be minimized and, if possible, all supplies should be taken on board prior to spud in. If it is necessary for the work boat to come alongside, it shall use the side where it is possible to drift away from the rig with engines shut down.
- The Standby Vessel must be positioned upwind of the rig.
- **Drilling operations must be suspended and a risk assessment conducted if the rig's gas detection system fails.**
- **Drilling operations must be suspended and a risk assessment conducted if the rig's mud monitoring system becomes unavailable while using a closed mud system.**
- **The Driller or his designee must check diverter and overboard line valves for the correct setting at the beginning of each tour. The Driller will be held accountable for this responsibility. The diverter insert packer must always be in and locked down after the riser is run (except during handling of the BHA).**
- Ignition Sources: When drilling out into known shallow gas reservoirs the rig must have the following procedures in place to prevent ignition of any gases returning to surface:
- All work on the electrical system must be done using a lock out procedure and work permit. At no time during the drilling of shallow gas will the rig allow any type of hot work with concerns to electrical systems.
- For surface stack / jackup rig operations, any crane work carried on during this time must be by work permit only. If the cranes are diesel powered, they must be fitted with spray systems on the exhausts. In circumstances where a spray system can not be fitted, such as when the exhaust is pointing upwards, a correctly sized and properly maintained spark arrestor is considered an acceptable alternative to the spray system.
- It should be noted that the handling of equipment onboard a rig by a crane has a high potential of sparks.
- No person on the rig floor will be allowed to use a hammer or any device which may cause a spark. If maintenance is required for equipment where potential sparks may occur, this maintenance must be postponed until the rig is in a position to ensure no gas is present.

- All maintenance where it is a requirement to open up explosion proof devices or purged areas must be postponed until the rig is in a position to ensure no gas is present.

6 PROCEDURES UPON ENCOUNTERING SHALLOW GAS

6.1 DRILLING RISERLESS FROM A FLOATING RIG

Riserless top hole drilling from floating rigs is the Company approved method.

6.1.1 ACTIONS IF SHALLOW GAS IS ENCOUNTERED WHILE DRILLING:

- Do not stop pumping, increase the pump strokes to maximum and switch suctions on the mud pumps to kill mud in the reserve pit.
- Raise the alarm.
- Prepare to release the drillstring.
- If after pumping all the kill mud the well continues to flow, release the drillstring.
- Initiate the pre-determined, rig specific move off plan.

6.1.2 ACTIONS IF SHALLOW GAS IS ENCOUNTERED WHILE TRIPPING:

If the bit is near bottom:

- Set the slips.
- Make up the topdrive/kelly.
- Start pumping kill mud at the maximum pump speed.
- Raise the alarm.
- Prepare to release the drillstring.
- If after pumping all the kill mud the well continues to flow, release the drillstring.
- Initiate the pre-determined, rig specific move off plan.

If the bit is less than 100 ft (30m) below the mud line.

- Set the slips.
- Make up the topdrive/kelly.
- Raise the alarm.
- Initiate the pre-determined rig specific move off plan.

6.2 DIVERTER PROCEDURES WHILE DRILLING

6.2.1 SURFACE BOP'S

At first sign of flow:

- Do not stop pumping.
- Open diverter line to divert/close diverter (both functions should be interlocked).
- Raise the alarm and make announcement on PA system. All non-essential personnel go to muster point and prepare to evacuate the rig.
- Increase pump speed to maximum rate.
- Switch suction on the mud pumps to heavy mud in the reserve pit.
- Prepare to evacuate rig of all personnel.
- In the event of a continuous flow after heavy mud is pumped, the rig should either continue to pump water to the well if this proves to be effective in controlling the flow, or go to a "dead-ship" condition. In any event the rig should be put in a "dead-ship" condition prior to final evacuation of the rig. Do not allow the emergency generator to start and power the rig.

6.2.2 SUBSEA BOPS

- Rigs with subsea BOP's must shut the well in when possible.
- Moving the rig off location immediately may be the best option when broaching occurs.
- At first sign of flow:
- Close the BOP's.
- Open the diverter line and close the diverter (functions must be interlocked).
- Raise the alarm and make announcement on PA system. All non-essential personnel must go to muster point.
- Kill the well by the "Wait and Weight" method or bullheading.
- Monitor seabed for broaching with ROV.
- Make preparations to move the rig off location if broaching is of concern.
- Pin connectors must only be used in areas known to have had no previous shallow gas occurrences, after a thorough risk assessment has been performed and approved by the Operations Manager Performance.

6.3 DIVERTER PROCEDURES WHILE TRIPPING

6.3.1 SURFACE BOPs

At first sign of flow:

- Set pipe in the slips, stab safety valve and make up top drive.
- Open diverter line, close diverter (functions must be interlocked).
- Raise the alarm and make announcement on PA system. All non-essential personnel go to muster point and prepare to evacuate the rig.
- Switch suction line to heavy mud in the reserve pit and start pumping at maximum pump speed.
- Prepare to evacuate the rig of all personnel.
- In the event of a continuous flow after mud is pumped, the rig should go to a "dead-ship" condition. Do not allow the emergency generator to start and power the rig.

6.3.2 SUBSEA BOPs

At first sign of flow:

- Set pipe in the slips, stab safety valve and make up the top drive.
- Shut in well at BOPs.
- Open diverter line, close diverter (functions must be interlocked).
- Kill the well by the "Wait and Weight" method or bullheading.
- Monitor for broaching at the seabed with ROV.
- Make preparations to move the rig off location if broaching is of concern.

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1 PROPERTIES

Hydrogen Sulphide (H_2S) is encountered in many regions of the world during well operations and in varying concentrations. It is extremely toxic, explosive and is heavier than air. In small concentrations it has an offensive rotten egg odor, while greater concentrations can paralyse the olfactory nerves so no odor is detected. When ignited it burns with a blue flame producing sulphur dioxide (SO_2) which can also cause serious injury.

2 WELL OPERATIONS PROCEDURES

When performing operations on a well where H_2S is suspected, all personnel must be trained in special procedures relating to well control, coring, well testing and well intervention. It is recommended that all H_2S equipment be installed and functional at least 1000 ft (300 m) or one week prior to penetrating the H_2S potential zone, or as required by local regulations, whichever is the most stringent.

Drilling may proceed through an H_2S bearing formation with tight control of sulphides in the mud once the casing is drilled out.

The pH of the mud system should be controlled to 10.5-13 and treated with a sulphide scavenger to prevent hydrogen embrittlement and corrosion of the drill string.

The Mud Engineer will check the soluble sulphides level, to ensure that it is not increasing.

If operations allow, a slug should be used to ensure the trip is not wet If H_2S is detected while tripping, this indicates a change in mud system condition caused by a drop in pH or an influx. The contingency procedures should be implemented and the appropriate H_2S Emergency Condition status confirmed onboard.

If H_2S less than 10 ppm H_2S in atmosphere, and a flow check confirms that the well is not kicking, then the mud system should be circulated and re-conditioned before resuming tripping operations.

If H_2S Emergency exists, the well will be shut in accordingly. The decision to RIH or strip to bottom, or circulate at this point to attempt remedial treatments (or even bullhead the pipe/annulus) should be made based on the well control implications, (if any) and available time for the crew to work on the mud system and rig floor. The latter will depend on the cascade system capacity and the prevailing weather conditions (for charging the cascade system).

Trip gas and drill gas may be circulated via the rig well control choke. Gas from the mud gas separator and the vacuum degasser must be routed to the overboard vent, normally routed up the derrick. If the well testing spread is in place and the capability to route the gas to the well test burners exists, this option should be considered provided the increased back pressure does not risk blowing down the MGS

Even in areas of high H_2S concentrations, H_2S may not be detected while drilling and its presence only confirmed during coring, well testing or when a kick is circulated to surface.

2.1 H_2S PROCEDURES WHILE CORING

Coring can be a dangerous operation due to formation gas trapped in the core barrel. The following practice should be followed during coring operations:

1. Tool box talk prior to the core retrieval operation.
2. After a core has been cut, circulate bottoms up and monitor mud for H_2S.
3. It is recommend to pump out of hole across reservoir section.
4. Only essential personnel to be on the rig floor.
5. Have breathing apparatus ready for use should conditions dictate.
6. All personnel in the area while the core barrel is pulled, broken out and opened must be wearing breathing apparatus and masked up.
7. H_2S monitors and aspirator tubes should then he used to monitor H_2S around the core barrel.

Consideration should be given to letting the core naturally vent for a period of time before processing the core. If there is any doubt, the core should be processed by personnel with BA and masked up.

2.2 H_2S PROCEDURES DURING WIRELINE OPERATIONS

Wireline operations in H_2S reservoirs can present serious hazards. The lack of circulation for prolonged periods during wireline operations presents a significant hazard from migrating gas. Running and pulling wireline in and out of the hole can encourage gas to enter the wellbore and migrate to surface.

Diligent monitoring of all fixed H_2S detectors must be observed during Wireline operations. Portable detectors should also be used on the rig floor.

2.3 H_2S PROCEDURES DURING WELL TESTING

The integrity of the well test equipment must be verified through pressure testing and function checking prior to testing operations. Well testing must be performed with the minimum number of personnel required in the immediate vicinity of the rig floor and test equipment.

2.3.1 TESTING PROCEDURES

Throughout the entire testing period, the testing contractor will monitor for H_2S at all strategic positions around the test package. Sufficient monitoring equipment for this purpose will be provided by the testing contractor.

1. The start of a well test or clean up must not be conducted at night without prior approval of the Operations Manager Performance with the following risk assessment, including H_2S assets.
2. All testing equipment will be approved for H_2S duty, conforming with NACE Standard MCO-75-88 (or latest revision).
3. Burners will be equipped with a continuous pilot and an auto igniter.
4. No open tanks will be used for collecting flow products. Surge tanks and separators will be equipped with overboard vent lines to below the lowest rig level.
5. There will probably be a background level of H_2S during testing which can come from a variety of sources, (incomplete combustion at the flare or weeping valves, flanges, chicksans, etc.). It is important to be aware of any increase in this background level, and take action should readings in excess of 10 ppm H_2S in air be recorded at the test site.
6. At the end of the test, the test string contents will be bullheaded into the reservoir or reverse circulated to the flare.

Weather conditions will be critical for well test operations. The well will not be flowed in the presence of any detectable level of H_2S in air if the wind speed drops below 10 knots.

2.3.2 TEST STRING RECOVERY PROCEDURES

Before pulling the test string:

1. A "bottoms up" circulation will take place through the choke. All personnel on the rig floor will be masked and breathing from the cascade air supply prior to "bottoms up" arriving at surface.
2. 5 stands before retrieving the first test tool at surface, which is liable to contain any reservoir fluid not circulated out by the previous circulation (e.g., reverse circulating valve), all personnel on the rig floor will be masked and breathing from the cascade system.

3 SPECIAL H2S PRECAUTIONS

If drilling known H_2S zones the following should be considered:

- All primary pressure containment equipment must be selected for H_2S service (including casing, drill pipe, BOP's and wellheads). For example, all casing and tubing strings should be L-80 or softer material (J-55, K-55, C-75) or special H_2S resistant grades.
- Use Grade 'E' or 'X' drillpipe whenever possible. Higher strength grades, such as 'G' or 'S', can be used providing the mud has been treated to combat the effects of H_2S on steel.
- All BOP equipment, Drill collars, HWDP, drill pipes and other drill string components worked in H_2S environment must be checked by defectoscopy and pressure test prior to use for drilling the follow well.
- A sufficient quantity of mud chemicals, including chemicals to neutralize H_2S, to treat at least 2 volumes of the hole should held on board.

4 WELL CONTROL OPERATIONS

Any influx of foreign fluid into the wellbore will be considered to contain H_2S

If H_2S is detected during a well control operation, the well must be shut-in immediately and the kill procedure re-evaluated. Reference must be made to the Offshore Emergency Response manual, which must detail actions to be taken when H_2S is encountered.

Bullheading is preferred well control procedure whenever significant levels of H_2S **have been detected.** If the decision is made to circulate out the kick (rather than bullheading it), all personnel involved in the well control operations must wear breathing equipment and mask up during the entire operation.

5 WEATHER

Since H_2S is heavier than air if, due to special circumstances, the influx is circulated to surface, consideration has to be given to the position of the gas vent line, which normally exits at the top of the derrick
Very careful consideration must be given at wind speeds below 10 knots, taking into account the wind direction and the operation about to be carried out, to determine if an operation should be postponed for more favorable weather conditions. Under no circumstances should gas venting proceed under still wind conditions. The risk of the gas cloud sinking back onto the rig under these conditions is high.

6 HSE EQUIPMENT AND TRAINING PROCEDURES

The following must apply:

- H_2S monitoring equipment must be continually surveyed and tested periodically.
- A temporary rig layout diagram clearly indicating the location of all H_2S safety equipment, including cascade plug in points will be posted beside the muster list on the rig.
- Personnel must be trained in H_2S procedures and personal breathing apparatus usage. (Refer to HSE Manual, HQS-HSE-PP-01, Section 4., Subsection, 3.1, Hydrogen Sulfide)
- All rig personnel will be advised of the equipment's Location.
- Adequate fixed H_2S detection devices must be located in key areas on the installation to measure H_2S concentrations in air to be used as detection triggers. (Reference to Manual Hydrogen Sulfide and Medical Protocols, HQS-HSE-PR-03, Section 6, Subsection 7, Hydrogen Sulfide).
- When H_2S is expected to surface, personal breathing apparatus must be worn.

7 EMERGENCY RESPONSE PROCEDURES

In the event of an emergency situation involving the release of H_2S into the atmosphere, if either the visual or audible alarm is triggered, all off duty and non-essential personnel must immediately don their personal breathing apparatus and proceed to the designated briefing area upwind of the wellbore.

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1 HORIZONTAL WELL CONTROL PROCEDURES

Horizontal and highly deviated wells use the same basic well control principles as those used for vertical holes. Downhole equivalent mud weights are calculated using the true vertical depth. However, there are several additional points to consider.

1.1 DETECTION

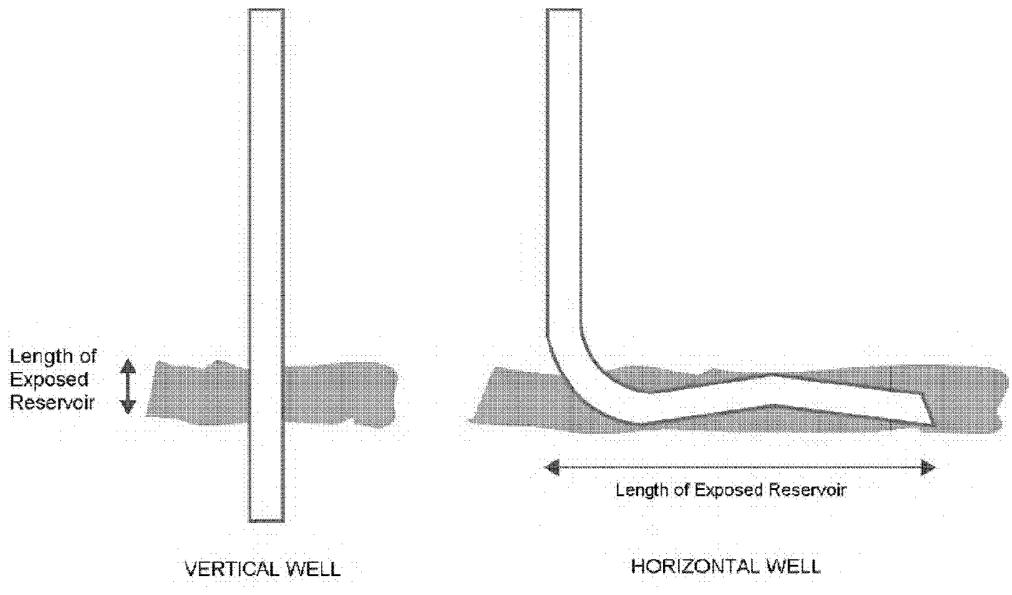
Kick warning signs are basically the same as for a vertical well, as is the required action (refer to Section 5).

1.2 PREVENTION

The following points should be noted:

The purpose of drilling a horizontal well is to improve well productivity and hydrocarbon recovery by maximizing reservoir exposure (see Figure 8.3.1).

Figure 8.3.1, Potential Capacity for Increased Kick Size with Horizontal Well



Therefore, influx flow rates, in the event of a kick, will be considerably greater than for a well drilled vertically through the same reservoir.

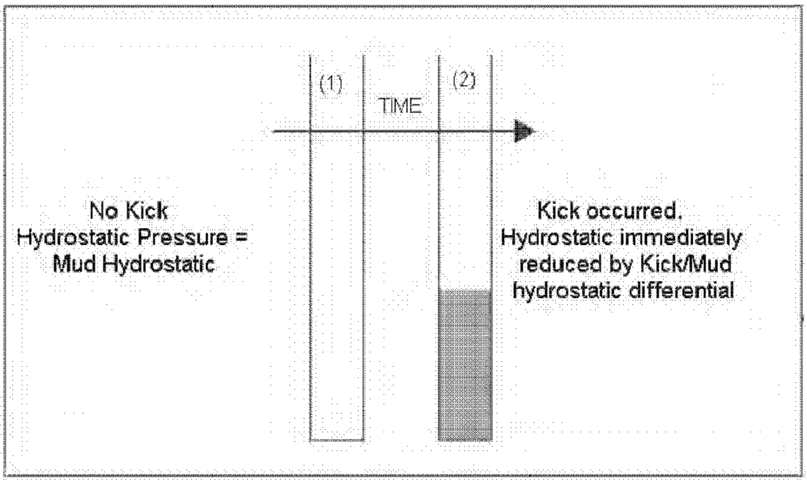
It is possible that shut-in pressures may be identical on both drillpipe and annulus even though a large kick has been taken. This would depend on the length of the horizontal open hole section but it does mean that it is not possible to use all of the kick data.

As long as any influx gas remains in the horizontal section of a well, no migration will occur. Only gas which has flowed or been pumped into or above the build section will migrate. Therefore the flow from the well may be slow at first, increasing very rapidly once the influx moves into the build section (see figure 8.3.2). At this point the hydrostatic pressure of the fluid in the annulus may have been lowered enough to induce a much larger kick into the well.

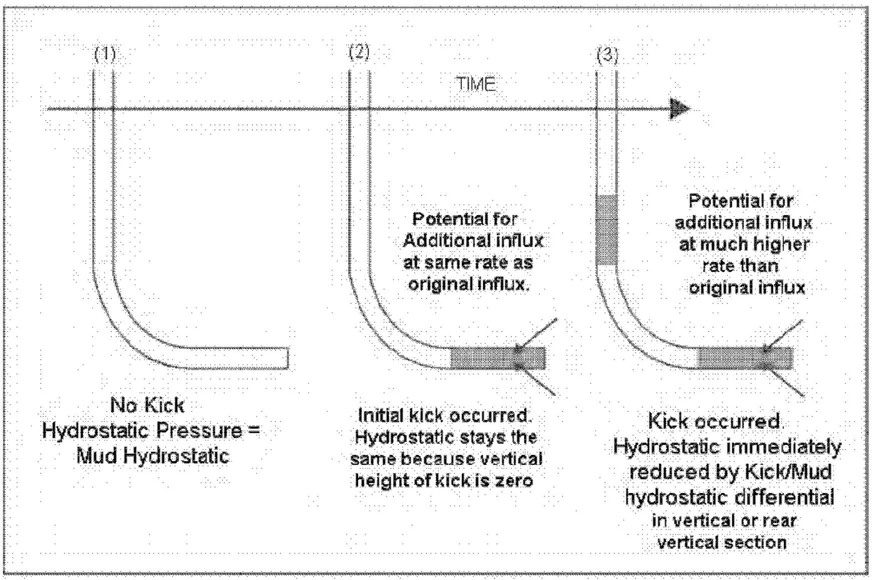
As a result, it is essential that:

- The pit(s) are closely monitored for small gains in volume.
- Flow Checks are extended to a minimum of 15 minutes.

Figure 8.3.2, Difference in Unloading: Vertical Well Versus Horizontal Well



VERTICAL WELL



HORIZONTAL WELL

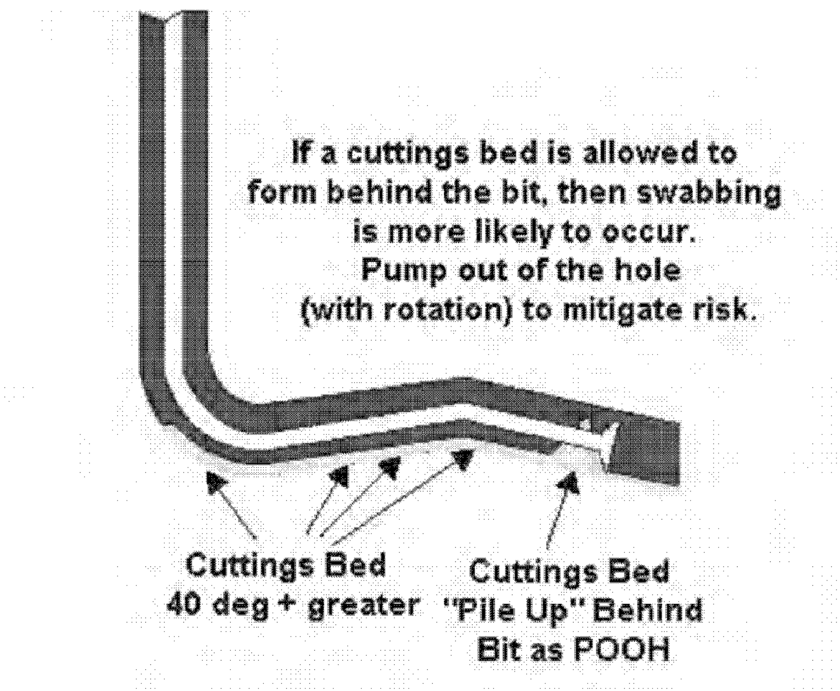
There is greater potential for swabbing when a large surface area of reservoir is exposed. Proper tripping procedures must be rigorously adhered to. When tripping out of the hole, a flow check should be made once the bit gets out of the horizontal section (see Figure 8.3.3).

To avoid swabbing, pump out of the open hole section to some point within the build section where cuttings beds will not form and swabbing is less likely to occur.

It is quite possible for the horizontal section to be full of reservoir fluid and yet the well is 'dead'. It is recommended that extreme caution should be paid when tripping back into the reservoir after a round trip. When back on bottom it is recommended to do a flow check after a partial bottoms-up as an influx may then be high enough in the well to be detected.

In the event of a kick while tripping it may not be possible to drop or pump down a dart. This will depend on the hole angle at the dart sub position. If it is not possible to install the dart into the dart sub the "Gray" valve can be used.

Figure 8.3.3, Effect of Tripping without Circulation in Horizontal Section



1.2.1 TRIP GAS

Trip gas may accumulate in a horizontal wellbore even when overbalanced mainly due to extent of reservoir exposure over the length of wellbore and density imbalance of the fluids i.e. the lighter fluid will percolate above the heavier fluid in the horizontal section.

When drilling inverted hole sections (above 90°) it is important to recognize this effect and therefore extended circulation time will be required to ensure that any trapped gas in high points, overgauge sections, etc., is removed.

1.3 LOST CIRCULATION

Lost circulation may be more likely in a horizontal well for two reasons:

- Fracture gradient at the casing shoe may be reduced because the formation stability stresses are greater at 90° compared with those of a vertical well. This problem is usually addressed by setting the last casing shoe as near to horizontal as possible e.g. ±80°.
- The ECD experienced on bottom is directly related to the length of the horizontal section drilled. For a long horizontal section, APL, and hence ECD, increases with measured depth, whereas the fracture gradient will remain largely unchanged over the length of the section. Higher flow rates needed to clean the hole and longer cuttings residence also tend to increase ECD.

As the potential for losses in a horizontal section is more likely, a lost circulation contingency plan should be drawn up and agreed prior to spud.

If possible, investigations should be made into optimizing fluid placement, fluid rheology, LCM concentrations etc., to ensure plugging of potential lost circulation zones. To effectively plug both the upper and lower half-circumference of the wellbore the following guidelines have proved successful.

a. Modify the rheology of the drilling fluid to ensure it is capable of carrying the required concentration of LCM material.
b. Slower placement to increase the chances of LCM passing along the upper part of the wellbore using a relatively higher LCM concentration than that normally found in the case of vertical or near-vertical wellbores.

2 DEVIATED/HORIZONTAL WELL KILL SHEET

2.1 COMPLETION OF KILL SHEET

(*Refer to Section 10 Subsection 2 for a worked example of a horizontal kill sheet*).

If we were to stop the pump when the kill mud is at the total vertical depth of the well then the SIDPP would be zero. At any time the kill mud is being pumped, the SIDPP, with the pump off, would depend only on how close the kill mud was to the total vertical depth.

2.2 STATIC COMPONENT OF CIRCULATING PRESSURE

The static pressure can be found at any time during the kill from the following equation.

Static Pressure
= SIDPP - [(KMW-OMW) x 0.052 x TVDp] ⇨ psi / ppg / ft
= SIDPP - [(KMW-OMW) ÷ 102 x TVDp] ⇨ kPa / kg/m^3 / m
= SIDPP - [(KMW-OMW) x 0.0981 x TVDp] ⇨ bar / kg/l / m

Where,
TVDp is the vertical depth of the kill mud at the time

2.3 DYNAMIC COMPONENT OF CIRCULATING PRESSURE

Dynamic pressure at any time in the kill is related to the MD of the kill mud. The dynamic pressure will increase as the mud is pumped. It can be found at any time in the kill from the following equation.

$$\text{Dynamic Pressure} = \text{SCRP} + (\text{FCP-SCRP}) \times \frac{MD_P}{MD_T}$$

Where,
MD_T is the total measured depth of the well, MD_P is the measured depth of the kill mud at that time.

As the kill mud is pumped along the pipe, the heavier mud will increase the dynamic pressure. This will increase from the initially recorded slow circulating pressure to the calculated final circulating pressure and depends only upon how far along the drillpipe the kill mud is. The FCP - SCRP is effectively the calculated increase in pump pressure. When $MD_P = MD_T$, kill mud is at bit, and the dynamic pressure will be the same as the FCP. When MD_P is small then the dynamic pressure is similar to the SCRP.

2.4 CIRCULATING PRESSURE

The circulating pressure while the kill mud is being pumped to the bit is simply the sum of the static and dynamic pressures.

Circulating Pressure = Dynamic Pressure + Static Pressure

It is important to ensure that when adding up the Dynamic and the Static pressures in the well, both calculations are made for the same physical point in the string.

The correct relationship for circulating pressures versus pump strokes is then plotted on the Deviated/Horizontal Kill sheet.

We can look at how this would work in practice with the completed sheet in Section 10 Subsection 2.

2.5 WHEN TO USE DEVIATED/HORIZONTAL KILL SHEET

The deviated kill sheet can be used for all deviated or horizontal wells but in many wells there will not be a large difference between the required circulating pressure and the values produced by the standard kill sheet.

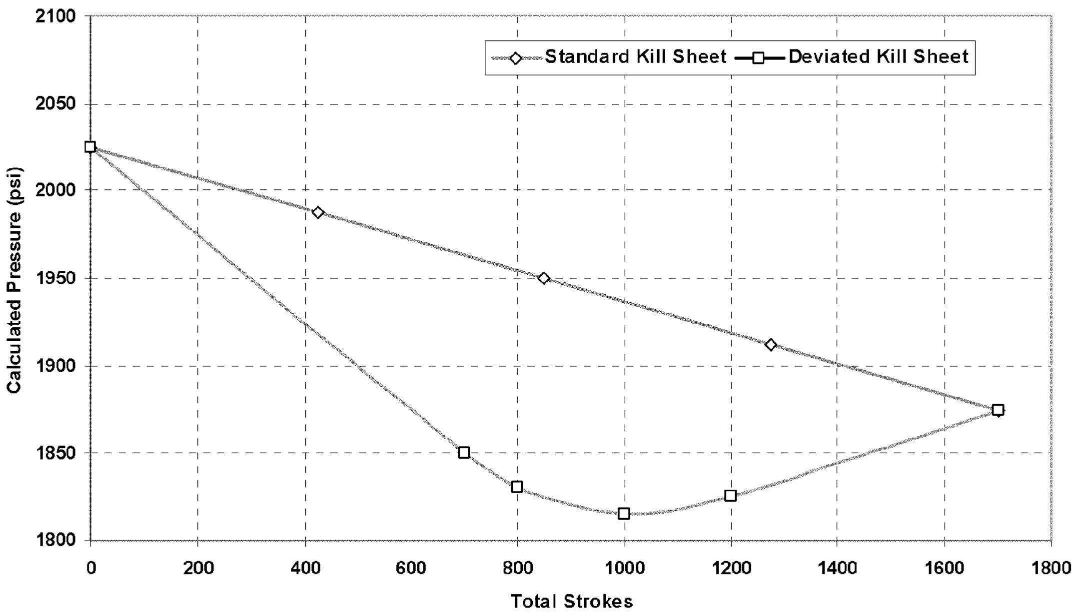
The difference between the circulating pressure (ΔP) calculated by the standard kill sheet and the deviated kill sheet can be calculated at any point in the well by the following equation.

ΔP = SIDPP x [($TVD_P \div TVD_T$) – ($MD_P \div MD_T$)]

The DP pumping schedule will be non-linear while pumping kill mud to the bit and will reach a minimum value before reaching the bit. However the annulus pressure is expected to remain approximately constant and close to SICP as the influx is displaced along the horizontal section.

It can be shown that the largest difference in pressure between the deviated and standard kill sheets in this case would be 127 psi. This is shown graphically in Figure 8.3.4.

Figure 8.3.4, Pump Pressure Schedule



The following guidelines can be used to determine when the deviated sheet should be used:

- A vertical kill sheet can be used if the initial, stable SIDPP is 100 psi or less, regardless of well profile.
- If the maximum difference between the circulating pressure calculated by the standard kill sheet and the deviated kill sheet is found to be less than 25 psi, the standard kill sheet can be used.
- A deviated kill sheet should be used if MAASP - SICP < 2 Δ P.
- This will depend on the field situation, such as shoe strength and casing pressure. If there is a risk of lost circulation the deviated kill sheet should be used in order to impose the least pressure on the wellbore.

2.6 DRILLER'S METHOD

The first circulation of the Driller's Method requires no changes to be used in a highly deviated or horizontal well. However, the pumping drillpipe pressure schedule (circulating pressures versus strokes graph) referred to in the procedures will be completed as described above.

2.7 FLUSHING GAS DOWNWARDS IN AN UPWARDS SLOPING HORIZONTAL WELL

Gas can be trapped in the upward sloping section of a horizontal well. A high pump rate will be required in order to flush it into the vertical section. This high pump rate should provide a downward mud velocity that is greater than the likely upward gas migration velocity. Once the gas has been flushed above the heel, it is essential to slow the circulation rate down. If the kick is gas which has dissolved in OBM then it should be pumped at a very slow rate down the section and into the less deviated or vertical section of the well.

2.8 STRIPPING IN HORIZONTAL WELLS

If a swabbed kick has already entered the deviated / vertical portion of the hole, it may be necessary to get the bit back to the bottom in order to clean up any kick fluid left in the well.

For circulating the kick out, it may be sufficient to strip pipe in until the bit is at the beginning of the horizontal section (at final TVD, but not MD). At this point, the Driller's or Wait & Weight Methods can be used to "kill" the well, filling the annulus with clean, kill density fluid while holding BHP constant.

After that, it should be possible to stage further into the hole, being careful to close the well in and use the Driller's Method 1st circulation technique to remove limited quantities of gas influx displaced up the hole as the drill string is pushed into the horizontal section. In this way it should be possible to eventually reach TD even when string weight is insufficient to strip through the horizontal section.

3 MULTILATERAL WELLS

Provided reliable hydraulic isolation is maintained, existing well control methods can be applied and each wellbore treated separately. Otherwise, calculations need to account for the weakest formation in either bore, possible kick from both bores and the different mud weights in both bores. Kick detection relies on the existing warning signs, pit gain and increased return flow.

3.1 INDICATIONS OF A KICK FROM THE ACTIVE WELL (CONTAINING THE DRILLSTRING)

Indicators are:

- A drilling break.
- SICP greater than SIDPP, if the wellbore is not horizontal.
- SIDPP remains relatively steady while SICP increases due to influx migration.

3.2 INDICATIONS OF A KICK FROM THE STATIC WELL

Indicators are:

- SIDPP = SICP.
- Both SIDPP and SICP increase due to influx migration.

3.3 KILL METHOD

Either the “Wait and Weight” or “Driller’s Method” can be used depending on the specific well. It should be noted that if the kick is from the static bore then the depth of kick should be taken from the junction.

The maximum allowable annular surface pressure (MAASP) should be calculated based on the weakest formation in all wellbores. Possible influxes from all wellbores should be considered.

3.4 CALCULATION OF MAASP FOR ACTIVE AND STATIC WELLBORES

For the **Active** wellbore (i.e. the bore containing the drillstring)

$MAASP_1$ can be calculated by the following equation.

$MAASP_1 = LOT - [(MW_1 - MW_{LOT}) \times 0.052 \times TVD_{1\ weak\ point}]$
⇨ psi / ppg / ft

$MAASP_1 = LOT - [(MW_1 - MW_{LOT}) \div 102 \times TVD_{1\ weak\ point}]$
⇨ kPa / kg/m^3 / m

$MAASP_1 = LOT - [(MW_1 - MW_{LOT}) \times 0.0981 \times TVD_{1\ weak\ point}]$
⇨ bar / kg/l / m

For the **Static** wellbore(s) (i.e. without drillstring) the possibility of different mud weights between the static and active wellbores must be considered. $MAASP_2$ can be calculated using the following equation.

$$MAASP_2 = LOT - [(MW_1 - MW_{LOT}) \times 0.052 \times TVD_{casing\ window}] - [MW_2 \times 0.052 \times (TVD_{casing\ window} - TVD_{2\ weak\ point})]$$

⇨ psi / ppg / ft

$$MAASP_2 = LOT - [(MW_1 - MW_{LOT}) \div 102 \times TVD_{casing\ window}] - [MW2 \div 102 \times (TVDcasing\ window - TVD2\ weak\ point)]$$

⇨ kPa / kg/m^3 / m

$$MAASP_2 = LOT - [(MW_1 - MW_{LOT}) \times 0.0981 \times TVD_{casing\ window}] - [MW2 \times 0.0981 \times (TVDcasing\ window - TVD2\ weak\ point)]$$

⇨ bar / kg/l / m

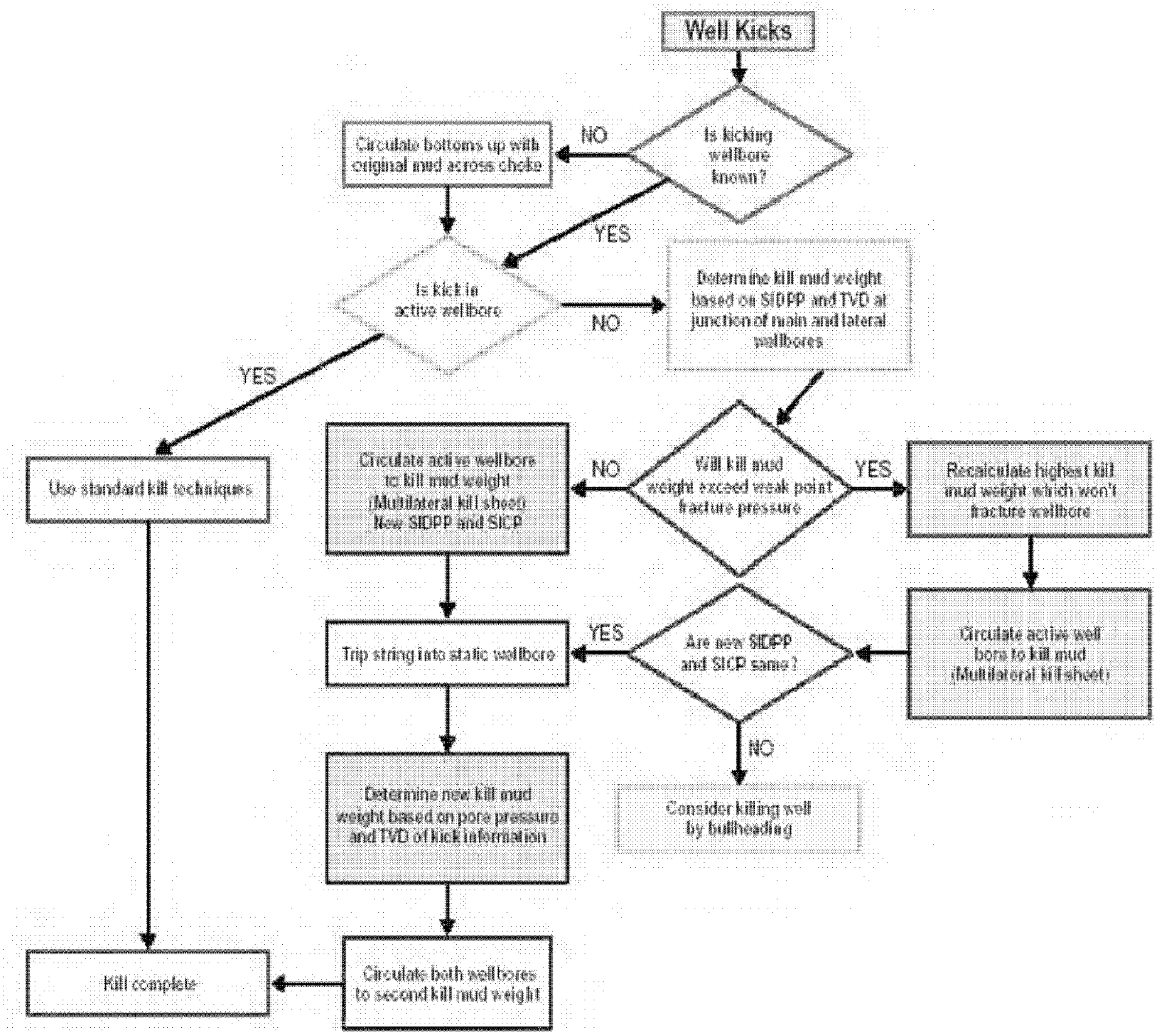
The final MAASP that should be used is the smaller of $MAASP_1$ or $MAASP_2$.

Caution should be taken when re-entering the main wellbore after completing the lateral, as by then the fluid may have been in the main bore for a long time and its condition unknown. Any leak at the shoe track creates the potential for hydrocarbons to be directly below the junction. In this case an under balanced situation could occur when running in the hole.

3.5 MULTILATERAL WELL KILL PROCEDURES

Once the well has been shut-in upon detecting a kick, a decision must be made regarding the most appropriate action to kill the well. As in a conventional single wellbore well, an attempt should always be made to use one of the standard kill techniques. This is particularly true when the influx is taken from the active wellbore. A flow chart (See Figure 8.3.5) has been prepared to help in determining the proper course of action.

Figure 8.3.5, Multilateral Well Kill Decision Tree



1 GENERAL

Wells drilled in deepwater use the same basic well control principles that are used on more standard wells. However, some situations which are considered "special" on standard wells may be encountered routinely on deepwater wells and these are highlighted in this chapter.

2 DEEPWATER WELL CONTROL EQUIPMENT

2.1 CONTROL SYSTEMS AND ACCUMULATORS

The working pressure for control systems in deepwater is often 5,000 psi (34,500 kPa, 345 bar) for water depths greater than 5,000 ft (1500 m).

Due to the necessity to pre-charge subsea bottles at the surface, working pressure of the bottles can be quite high. Accumulators charged to 5,000 psi (34,500 kPa, 345 bar) differential on the sea floor must be vented before retrieving the BOP stack to the surface.

2.2 BOP PRESSURE TESTING

In deepwater, consideration must be given to the effect that mud weight has upon BOP pressure ratings when testing. The differential pressure between the mud column and seawater gradient must be considered when pressure testing the BOP's.

For example, a well in 8,000 ft (2,400 m) of water with 15 ppg (1800 kg/m^3, 1.8 kg/l) mud has a differential pressure across the BOP's of 2,700 psi (18,600 kPa, 186 bar). For a BOP rated to 15,000 psi (103,400 kPa, 1034 bar), the maximum surface test pressure for these conditions would be 12,300 psi (85,000 kPa, 850 bar).

2.3 BOP STACK AND RISER

It is recommended to have pressure monitors placed on the BOP stack while operating in deepwater, as follows:

- A low-pressure monitor (rated to the maximum anticipated hydrostatic mud weight) may be placed above the uppermost annular preventer. This monitor will give an indication of cuttings build up in the riser and, upon shutting-in the well, will indicate if gas is rising in the riser annulus.

- A high-pressure monitor (rated to the BOP stack working pressure plus hydrostatic pressure of the sea water at maximum water depth) may be placed in the choke/kill line to monitor pressure below the lowermost rams.
- It is preferable to have an instrumented BOP stack with direct readings of pressure and temperature. Where available, the pressure readout should be in both absolute (actual gauge pressure) and differential (compensated for water depth). These gauges provide a more accurate indication of the conditions at the BOP stack and remove uncertainties that arise from estimating pressure drops from a fluid at low temperature and high pressure. All pressure gauges must clearly show what pressure (absolute or differential) is being displayed.

NOTE: Special consideration must be given to well activities which result in a negative pressure differential on the BOP stack (i.e. when external seawater hydrostatic pressure is greater than internal BOP pressure). Negative differential pressures of as low as 500 psi can result in BOP damage, such as collapsing of the BOP bonnet seals and subsequent leaks. Check your BOP rating for such circumstances.

If a large negative pressure differential is suspected to have occurred, then the integrity of the BOP should be confirmed prior to continuing operations.

2.4 BOP RAMS

In deepwater wells, ECD's, ESD's and hole (or riser) cleaning can become critical with the resulting use of tapered drillstrings. When such strings are used the following should be noted:

- The number and size of pipe rams required will be determined by the drillstring geometry.
- The BOP stack must be equipped with ram configurations that allow for 2 sets of rams capable of closing on the pipe that is across the BOP while drilling and 1 set for the other size of pipe.
- Caution needs to be taken when using variable bore rams (VBR) since, for some of the smaller ranges of pipe, the amount of weight that can be hung off on them is limited. For DP operations it's important that the rams are capable of supporting the weight of the drillstring should the rig need to disconnect.

Figure 8.4.1, Typical VBR Hang-off Capacities

VBR HANGOFF CAPACITY (POUNDS)				
BOP Size	**Description**	**Pipe 5"**	**Pipe 3 ½"**	**Pipe 2 ⅞"**
11" 15M	5" to 2 ⅞"	450,000	150,000	40,000
16 ¾" 10M	5" to 2 ⅞"	450,000	294,000	70,000
18 ¾" 15M	5" to 3 ½"	450,000	140,000	

The hang-off capacity of the rams being used must be known – refer to the manufacturer's recommendations.

3 SHALLOW WATER FLOWS (SWF)

3.1 CAUSES OF SHALLOW WATER FLOWS

Shallow Water Flows (SWF), or the flow of water and entrained sand from sub-seafloor strata past the drill bit or surface casing, is a phenomenon typically found in deepwater drilling. Shallow water flows are due to rapid sedimentation in river delta areas overlain by shale which prevents any water and gas from within the sands escaping during compaction caused by further, rapid sedimentation. These sand deposits grow in thickness at a rate of 500 -7,000 feet (150-2100 m) per million years, creating shallow pressure zones near the surface.

3.2 COMBATING SHALLOW WATER FLOWS

3.2.1 WEIGHTED FLUIDS

The most common method of drilling these intervals requires the use of weighted fluids and the following should be noted:

- This can be expensive since these sections are drilled riserless and the fluid is not recovered.
- Remote Operated Vehicles (ROVs) should be deployed to observe the seabed when drilling in areas where SWFs may occur to enable the detection of flow as soon as possible.
- The most common WBM used to drill the intermediate intervals of deepwater wells is a sodium chloride-based system. The salt concentration is normally maintained at levels of 20% or greater. These levels yield some degree of shale inhibition and gas hydrate control.

3.2.2 CHEMICAL ALTERNATIVES

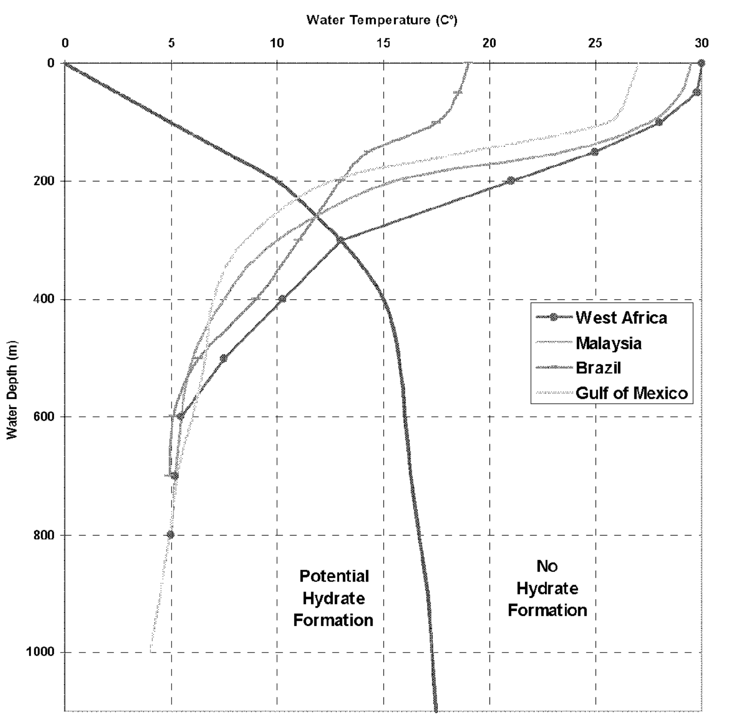
- Polymers or resins may provide a means of sealing off the SWF zone and adding strength to the sediments.

Once the SWF zone has been drilled and the casing run and landed, the well needs to be cemented in order to isolate the problem formation(s). Successful cement jobs have been achieved using foamed cement, which continues to transmit original hydrostatic pressure throughout the thickening process, unlike conventional cement slurries, which undergo a reduction of hydrostatic pressure while setting, which in turn may allow the well to start flowing.

4 HYDRATES IN DEEPWATER

Figure 8.4.2 below shows the average water temperatures versus water depth for various parts of the world. This graph shows that the conditions for hydrate formation almost always exist in wells drilled in more than 820ft (250m) of water.

Figure 8.4.2, Regional Water Temperature vs Depth



4.1 HYDRATE PREVENTION

Hydrate formation while circulating is less likely due to the heat brought up from the wellbore.

Any delay in circulating out gas will allow the mud throughout the well to cool, thereby increasing the potential for hydrate formation. This factor favors the use of the Driller's method for well kill.

Prior to drilling each section a decision should be made as to which of the following kill methods will be used:

- Have available a sufficient volume (hole volume but not riser volume) of reserve kill mud, pre-mixed to a selected density. With kill weight mud already prepared there would be no delay in starting the kill process, so a 'No-Wait and Weight' Method could be used. Unless other factors are known, the kill mud density should be 1 ppg (120 kg/m3, 0.12 kg/l) over current mud weight. The mud weight can be reduced quickly by dilution if necessary and permit the kill procedure to begin with a minimum of delay.
- Kill the well using the Driller's Method, i.e. can start circulating immediately.
- Use the conventional Wait and Weight Method. **(NOTE: Well Cooling Rate.)**

Fill the kill line with hydrate inhibitor and inject into well during the kill operation.

To calculate the proper amount of hydrate inhibitor to be used while circulating, the following procedure should be followed:

From Figure 8.4.2, calculate the degrees of hydrate suppression required (DHSR). The DHSR is the difference between the actual seabed temperature (TSB) and the hydrate formation temperature (TH) at the seabed. DHSR = TH - TSB.

For example, for a well being drilled in 2000 ft (600 m) of water in the Gulf of Mexico (see figure 8.4.2 for data):

- TH = 16°C, taken from the curve at the right side of the "Potential for Hydrate formation" zone at 2000 ft/600 m.
- TSB = 6°C, taken from the water temperature curve for at 2000 ft/600 m depth.
- So DHSR = 16°C - 6°C = 10°C.

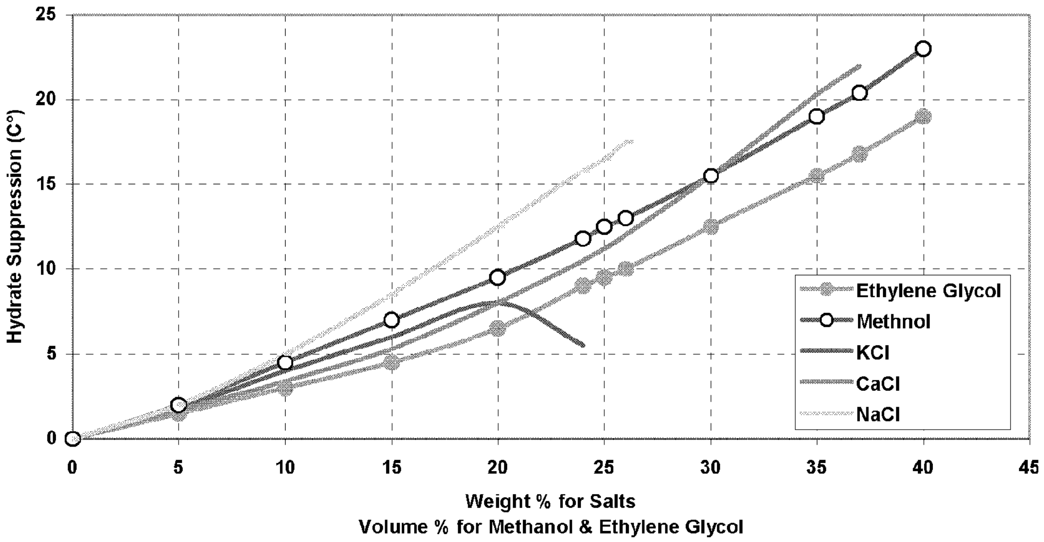
Look up the concentration of inhibitor necessary to provide the proper level of hydrate suppression (see figure 8.4.3 for the amount of hydrate suppression that is provided by different concentrations of common chemicals).

Mixtures of inhibitors can be more effective than using single components, but have not been tabulated here. Simulators are available to make these calculations. So, for the example, the following would be acceptable:

- - 17 Wt% NaCl, or
- - 23 Wt% CaCl, or
- - 21 Vol% Methanol, or
- - 26 Vol % Ethylene Glycol

NOTE: These are the inhibitor concentrations for the fluid that is returning up the choke line, which will be a blend of the inhibitor and the drilling fluid. Circulation rates of the drilling fluid and the inhibitor must be balanced so that the proper concentration is maintained in the choke line.

Figure 8.4.3, Hydrate Suppression Provided by Common Chemicals in °C



4.2 EXTERNAL HYDRATES IN WELLHEAD CONNECTOR

In areas where gas may percolate up from outside the conductor, hydrates can build up within the wellhead and riser connector cavities.

Once hydrates have formed inside the wellhead connector cavities, cycling the "unlock" and "lock" function repetitively will exacerbate the problem by compacting the solid slug and allowing new hydrate to form.

To prevent hydrates from collecting in the wellhead connector, one or more additional hydrate seals should be added to the connectors.

Both new and existing upgraded connectors can be built with flush ports built into the connector to circulate seawater, glycol or methanol through the connector internal cavities. (**NOTE: Methanol is preferred; glycol is effective to -6°C).**

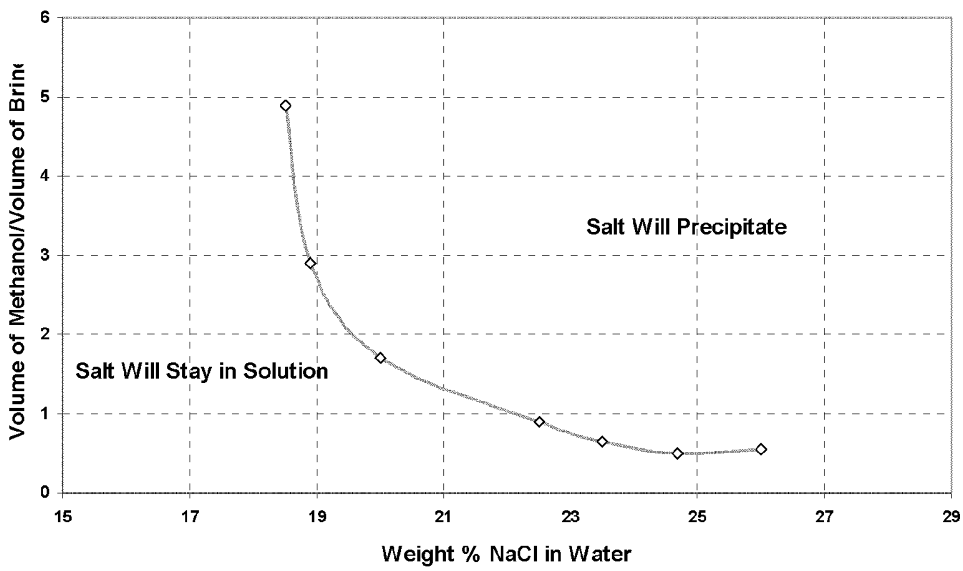
Also available is a "gas mat" that seals around the conductor casing to divert any leaking gas away from the connector.

4.3 HYDRATE REMOVAL

Several methods may be used to remove hydrates once they have formed:

- One method is to pump a chemical mixture of HCL down one string and caustic down another string. Allowing them to mix at the bottom will generate heat. This solution involves pumping two chemicals that are dangerous to handle. These chemicals are also very corrosive and can damage equipment if not properly inhibited.
- A similar approach is a chemical system in which sodium nitrite mixes and reacts with an ammonium salt. The reaction yields a lot of heat and the final products are nitrogen gas and sodium chloride, both of which are environmentally friendly. This process is called "SGN".
- The most commonly used hydrate inhibitors for deepwater wells are methanol and glycol. On a weight basis, methanol provides the greatest inhibition. However, methanol is generally more toxic than glycol, has a lower vapor pressure and flash point temperature and because of these properties requires special provisions for its storage. Care must also be taken when using brines as alcohols, such as methanol and ethylene glycol, lower the solubility of most inorganic salts in water (see Figure 8.4.4).

Figure 8.4.4, Salt Solubility with Methanol Mix



5 TEMPERATURE EFFECTS ON MUD DENSITY AND RHEOLOGY

In deep, cold water the temperature profile along the well path decreases from surface to the sea floor and can fall as low as the normal freezing point of water.

The reduced temperature has a marked effect on the circulating temperature for the whole well and will affect both the density and viscosity of the mud.

5.1 DENSITY EFFECTS

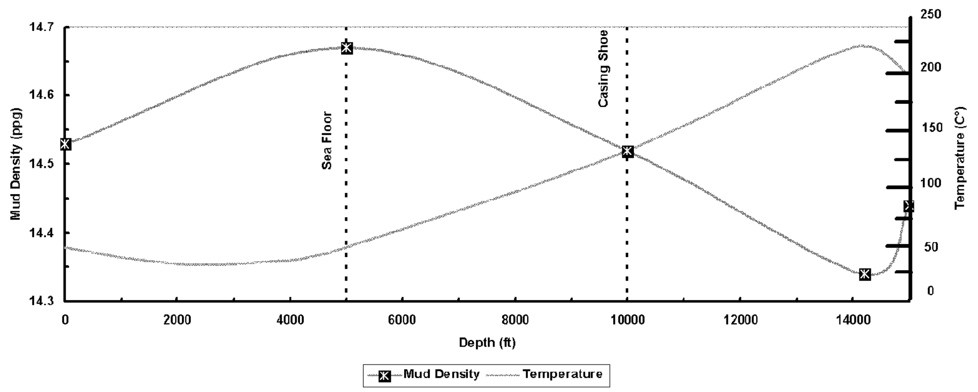
The cooler mud in a deepwater well will be denser than in wells in shallow or moderate water depths. Figure 8.4.5 illustrates the effect of temperature on the density of mud.

Mud density increases with increasing pressure and decreases with increased temperature.

As pressure and temperature both increase with depth (below the mud line), mud density may increase or decrease with depth, depending on the relative contribution of the pressure and temperature effect.

In WBM the pressure effect is very small. In the example shown (figure 8.4.5) it can be seen that the nominal 14.5 ppg varies from 14.35 ppg to 14.65 ppg as the temperature changes along the flow path indicating that the temperature effect is predominating. In low temperature wells drilled with OBM the pressure effect may predominate.

Figure 8.4.5, Temperature Effect on Mud Density

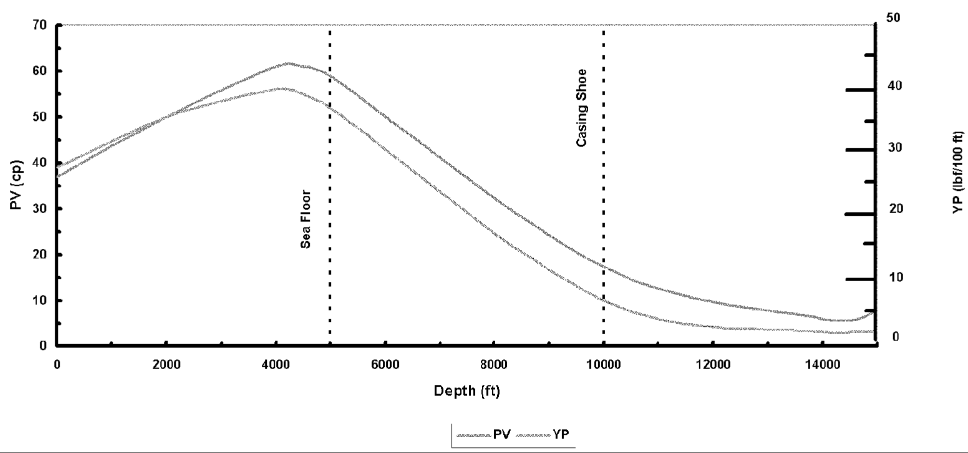


5.2 RHEOLOGY EFFECTS

The cooler mud in a deepwater well will be more viscous than in wells in shallow or moderate water depths.

Figure 8.4.6 illustrates the effect of temperature on the viscosity of mud.

Figure 8.4.6, Temperature Effect on Mud Viscosity



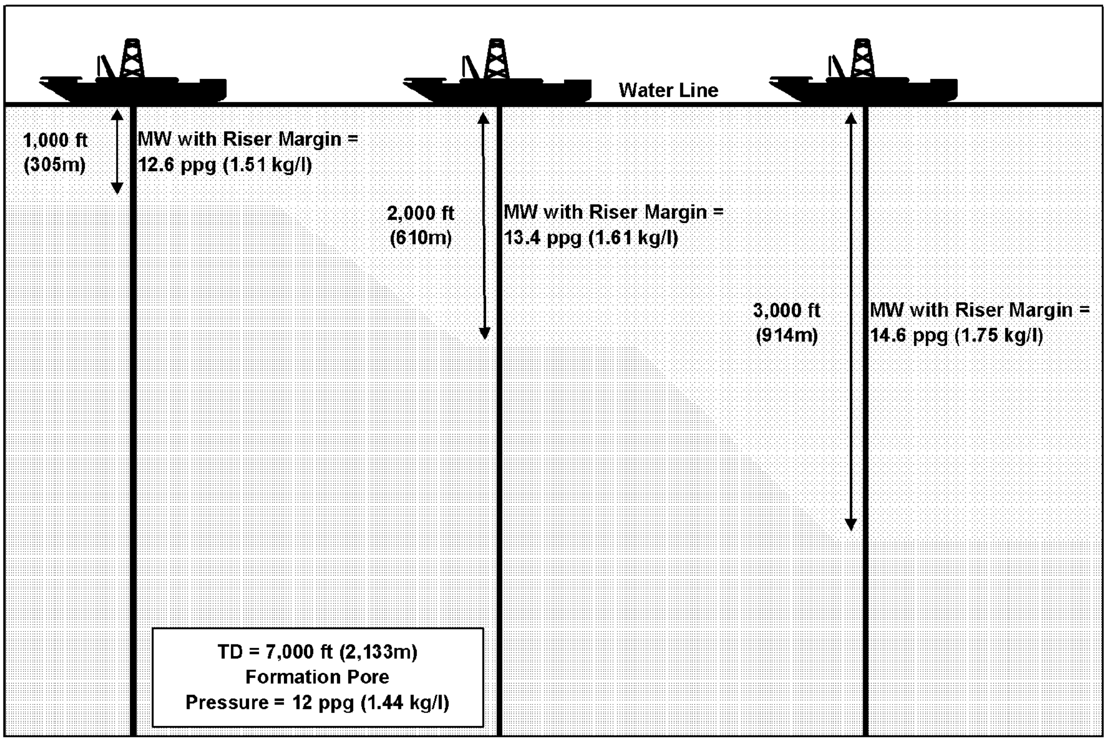
The cumulative effects of temperature on density and rheology can lead to errors in determining several key parameters:

- Leak Off Test (LOT) recording.
- Slow Circulating Rate (SCR) pressures.
- Choke Line Friction Loss (CLFL) pressures.
- Shut-in Pressures.

The above information demonstrates the importance of circulating through the choke line prior to beginning a well kill operation.

6 RISER MARGIN

Figure 8.4.7, Riser Margin



Riser margin is the increment of mud weight that is added to the mud weight required to drill the well, in order to compensate for the removal of the riser (and the effect of the mud column contained within it) and so provide sufficient hydrostatic pressure to maintain primary control of the well from the mud line to TD.

Riser margin is calculated as follows:

$MW_2 = ((MW_1 \times TVD) - (L2 \times SW)) \div (TVD - (L1 + L2))$

Where,
MW_2 = MW with Riser Margin (ppg, kPa, kg/l)
L1 = Air gap (ft, m)
MW_1 = Mud weight (ppg, kPa, kg/l)
SW = Density of seawater (ppg, kPa, kg/l)
L2 = Water depth (ft, m)
TVD = True vertical depth from flowline (ft, m)

- When the riser is disconnected the hydrostatic pressure of seawater replaces the hydrostatic pressure of the mud column from the rig to the wellhead.
- As water depth increases so does the riser margin mud weight. See figure 8.4.7 as an example.
- As we drill in increasingly deeper water, sometimes it may not be practical to carry a riser margin as it becomes too large to effectively drill a well. In such a case, the closed BOPs will maintain bottom hole pressure if the riser is removed.

7 MAASP IN DEEPWATER

CLFL in deepwater complicates a well kill operation. In the following example, assume gas is swabbed into a well.

- Assume the SCRP pressure is 500 psi (3450 kPa, 34.5 bar) and that the choke is opened enough to compensate for the CLFL so that the bottom hole pressure is held constant at the original pressure of 5,000 psi (34500 kPa, 345 bar).
- The well is then circulated until the influx just reaches the choke line.
- Now assume the gas bubble enters the choke line:

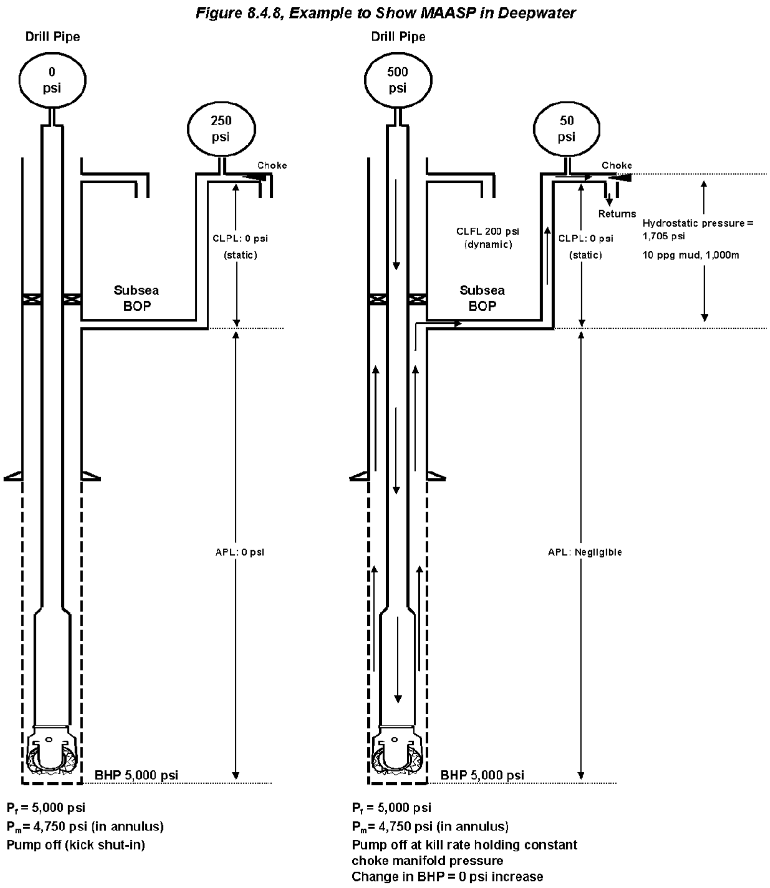
With a water depth of 3280 ft (1000 m) and a mud weight of 10ppg (1200 kg/m^3, 1.2 kg/l) the casing pressure would need to increase by 1705 psi (11760 kPa, 117.6 bar) just to offset the loss of hydrostatic pressure to maintain a constant BHP of 5000 psi (34500 kPa, 345 bar).

Pressure = SICP + (10ppg x 0.052 x 3280ft)
= 50 + 1705 = 1755 psi.

SICP + (9.81 x 1000 m x 1200 kg/m3)
= 345 + 11755 = 12100 kPa

SICP + (1000 m x 1.2 kg/l) x 0.0981
= 3.5 + 117.5 = 121 bar

Figure 8.4.8, Example to Show MAASP in Deepwater



If we assume that the CLFL can also drop significantly, since gas can flow with much less friction, then the pressure could increase another 200 psi (1380 kPa, 13.8 bar) to 1955 psi (13480 kPa, 134.8 bar).

- As the gas clears the choke line and is replaced with mud, the casing pressure should be adjusted back down to zero.

- If the well is being killed with a high SCR, these pressure fluctuations could occur very quickly and the choke operator needs to be very skilled to maintain the proper pressures.

This example demonstrates the increased magnitude of pressure fluctuations that may occur during well control operations in deepwater. Therefore, influxes need to be circulated out at slow rates to simplify well control operations in deepwater.

8 DEEPWATER WELL CONTROL THEORY AND PROCEDURES

As water depth increases there is a reduction in the difference between the mud weight required to balance the formation pore pressure and the weight causing formation fracture. As a result, wells drilled in deepwater tend to have much lower kick tolerances than wells in shallower water. This fact, in addition to the problems that can occur if gas enters the riser, makes it very important to prevent kicks and, should one occur, detect and control it at an early stage.

Another problem that occurs with increasing water depth is the impact of increased annular fluid density (riser cuttings) in creating higher than assumed hydrostatic pressures. Higher pressures can lead to fracturing of low strength casing shoes (or weak zone) which can lead to a kick. Boosting the riser becomes more important with increased water depths.

8.1 KICK PREVENTION

The standard kick prevention methods apply in deepwater as in shallow water (refer to Section 4). However, due to the narrow margin between pore pressure and formation fracture pressure, the overbalance safety margin will be minimal.

Therefore, special care must be exercised during trips to prevent swabbing and surging.

8.2 KICK DETECTION

8.2.1 SURFACE DETECTION

The same warning signs, pit gain and increased return flow, apply in deepwater wells.

Prior to drilling each section, the required kick detection sensitivity and primary detection method to be used for that section must be determined.

The kick detection sensitivity will usually be based on the calculated kick tolerance (i.e. the detection sensitivity will be less than the kick tolerance, allowing for shut-in time).

The detection method will depend on the drilling fluid type, hole geometry, rig equipment, etc. For example, in a horizontal well, pit gain would be the primary method of kick detection, while flow checks would be used for vertical wells.
Modern kick detection systems using computers and a variety of sensors are also available.

One such example is acoustic kick detection. Acoustic kick detection is a method of identifying gas influxes based on the phenomenon that gas effects the propagation of pressure waves within the mud circulation system.

8.2.2 DOWNHOLE DETECTION

Downhole influx detection can provide data that cannot be collected with surface equipment and should significantly shorten warning times. In general downhole sensors should be near the bit but there is no guarantee that the influx will not occur up the hole above the sensors.

Because many kicks occur on trips, MWD sensors may be of no use unless tripping practices are modified.

8.3 CIRCULATING SCHEDULE FOR KILL AND CHOKE LINES

If glycol or base oil (when using OBM) is inside the choke and kill lines while drilling with weighted mud, they should be circulated to the same mud as the drilling mud in the hole prior to starting the kill operation.

If the choke and kill lines are filled with drilling mud, they are to be circulated every tour to prevent settling that can plug the choke and kill lines.

8.4 SHUT-IN PROCEDURES

Standard shut-in procedures also apply to deepwater with some additional requirements.

- Pumps may be stopped first to prevent pumping influx higher up the hole and possibly into the riser.
- The riser must be monitored for flow.
- If gas is detected in the riser, the decision may be taken not to hang-off the drillpipe on a set of rams but, with the annular preventer closed, continue to

suspend the pipe with the Drillstring Compensator (DSC) unpinned and overpressured.

- This will eliminate any relative motion between the rig and the drillpipe that could create a leak between the diverter element and the drillpipe.
- After the riser is cleared of gas, the pipe must then be hung off.

8.5 KILL PROCEDURES (INCLUDES INSTRUMENTED BOP)

Before beginning each phase of drilling operations, the well geometry, kick tolerance and the potential for hydrate formation need to be carefully reviewed to determine which kill procedure must be used (Driller's, No Wait and Weight, or Wait and Weight).

- If removing the influx ASAP is the preferred option, the Driller's Method can be used for wells where the drillpipe volume is greater than the open hole volume, since the maximum pressure at shoe will be the same as for the Wait and Weight Method.
- Prior to starting the kill procedure and if the BOP stack arrangement permits, the kill and choke lines should be circulated in order to break the mud gels.
- A single line kill should be used in most instances (especially for instrumented stacks) with the circulation rate slowed at the end of the kill.
- Two line kills, using the uppermost outlets on both the choke and kill sides, may be used in cases where the kill speed using a single line would be too slow.
- The beginning kill rate selected should be chosen so that the CLFL is less than the shut-in casing pressure (SICP). Prior to the start of the kill procedure the relative magnitudes of the pressures involved need to be determined and if the CLFL is not less than the SICP the actions described below should be taken.

8.5.1 SIDPP AND SICP > MAASP

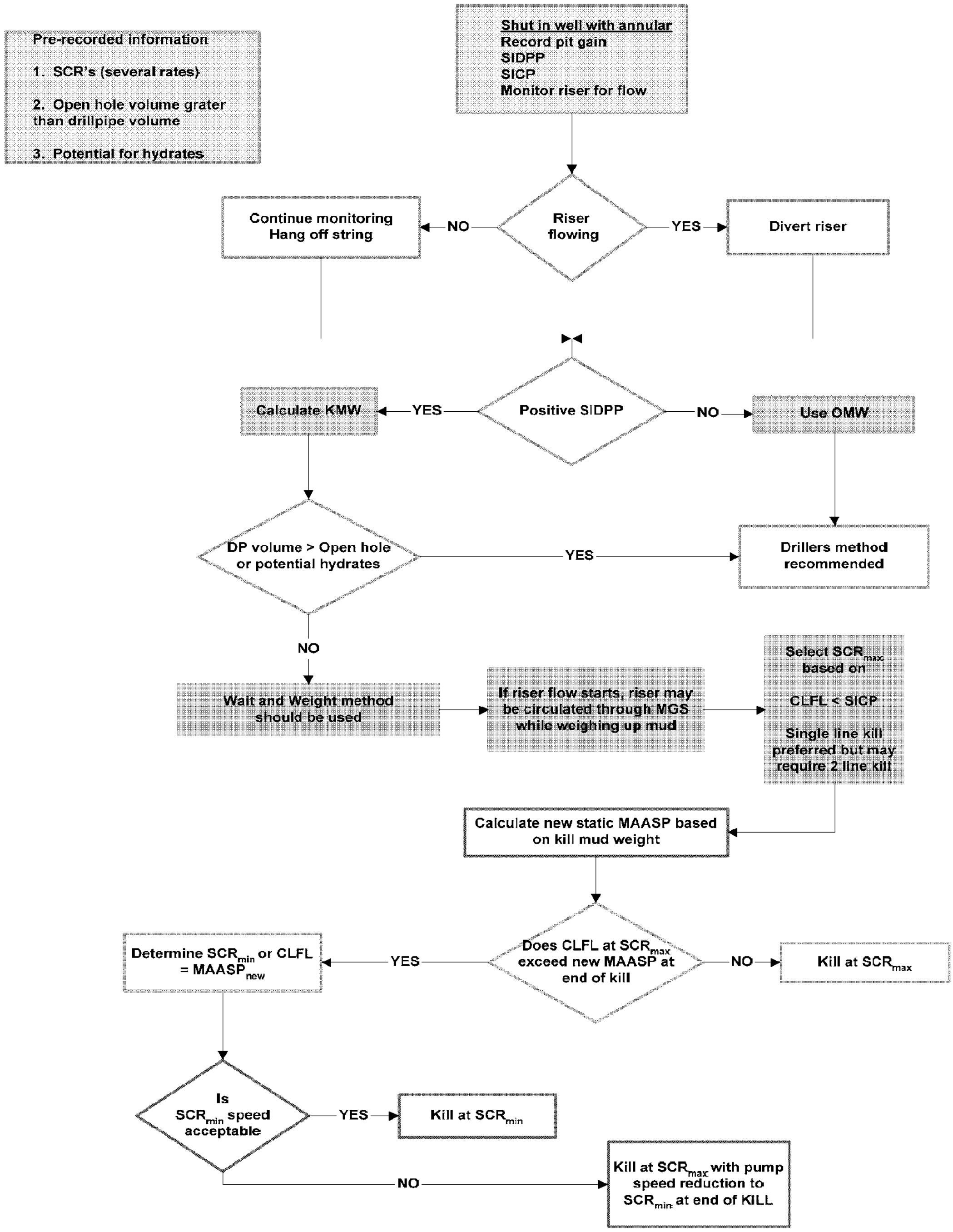
Under these circumstances, attempting to circulate out an influx will probably fracture the formation and may result in an underground blowout. The following may indicate that an underground blowout has occurred:

- A sudden break in surface pressures during the initial build up to equilibrium.
- Rapid fluctuations in casing pressure.
- Drillstring is on vacuum.

8.5.2 SICP < CLFL

If it is not possible to reduce the SCR to a value where associated CLFL is less than the SICP, then the casing shoe must be able to withstand the overpressure amount of CLFL - SICP.

Figure 8.4.9, Decision Tree for Deepwater Kill



8.5.3 SIDPP < CLFL

The CLFL will be sufficient to keep the well in overbalance. When most of the influx is circulated out the choke will be opened completely and the pump pressure will start to increase from its measured SCR pressure.

8.5.4 BEGINNING KILL - BRINGING PUMP UP TO KILL SPEED

On BOP stacks equipped with pressure sensors, the pressure sensor should be used to maintain a constant pressure at the BOP stack while bringing the pump to kill speed.

This will remove the inherent uncertainty that exists if the CLFL pressure schedule is as described in Section 4 Subsection 3 Item 3.

8.5.5 FINISHING KILL (ACCOUNTING FOR CHOKE LINE FRICTION)

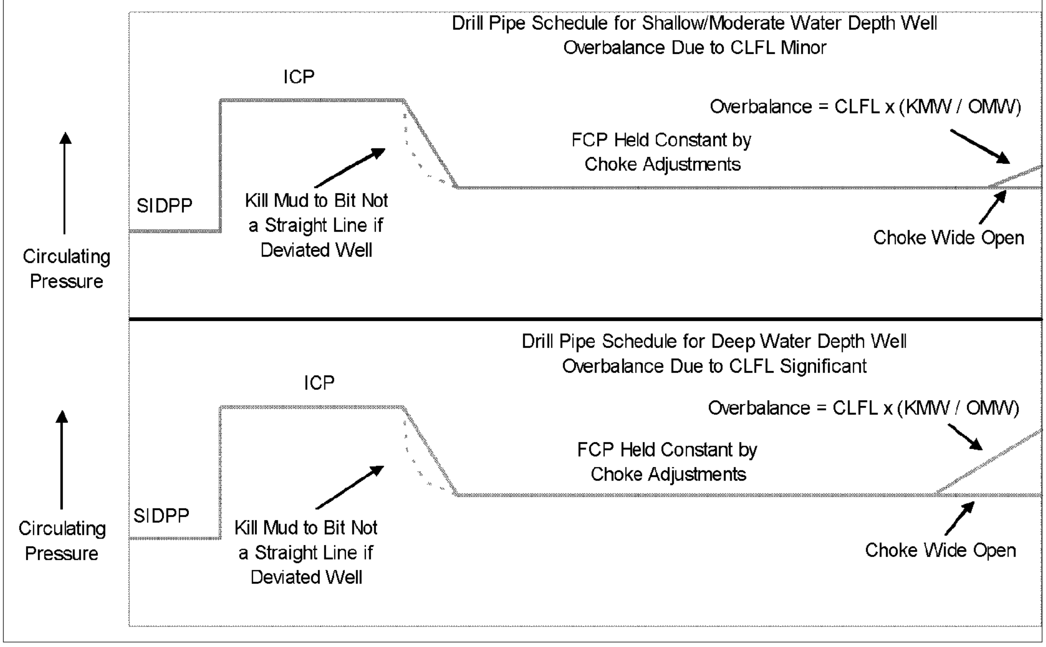
Since the kill mud's density is selected to just balance the formation pressure while static, at the end of the kill process the CLFL caused by circulation acts to overbalance the well.

There will come a time when the kill mud reaches sufficient height in the annulus such that the hydrostatic pressure added to the CLFL pressure will balance the formation pressure and the choke will be in the fully open position.

- As the mud rises the hydrostatic pressure will continue to increase.
- If the rate is kept constant and heavier kill mud is being pumped, the friction pressure will also increase.

Figure 8.4.10 below demonstrates this effect. The first diagram shows the effect on a well in shallow water. The second diagram shows that the effects can be greater in deepwater.

Figure 8.4.10, Comparison of Drill Pipe Pressure Schedules



Two options exist to eliminate exposing the formation to the overpressure at the end of the circulation.

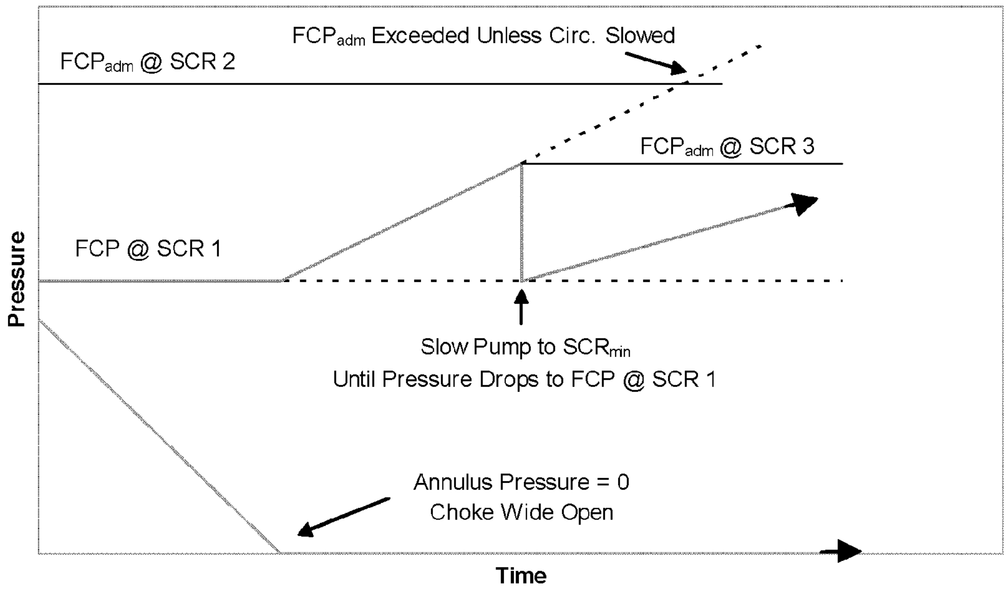
Option 1. If kill mud has been circulated up to the BOP stack, then the following may be considered. At the point the choke is fully opened, close the lowermost ram below the choke outlet to isolate the open hole. Circulate kill mud down the kill line and up the choke line at any rate and then proceed with clearing any gas trapped below the stack.

Option 2. At the point the choke is fully opened, the pump pressure will continue to rise. If the well is being killed at a rate where the CLFL > New MAASP, the casing shoe fracture pressure will eventually be exceeded.

FCPadm = SCRP X (KMW/OMW) + New MAASP
Where FCPadm = Maximum admissible FCP

- To eliminate this problem the pump rate can be reduced.
- After the pump pressure has risen to near the FCPadm, (i.e. to within about 25 psi) the pump rate should be reduced until whichever occurs first; the pump output pressure drops to the original FCP value, or the rate is reduced to SCRmin (see figure 8.4.11).

Figure 8.4.11, Pressure Approaches FPC $_{adm}$



- When the rate is reduced to SCRmin no other adjustments should be required to finish killing the well.
- If the pressure drops to FCP @ SCR 1 with a rate still exceeding SCRmin, the process will need to be repeated until the rate is reduced to SCRmin.
- The circulating pressure should be kept as close as practical, slightly above FCP until the rate is reduced to SCRmin.
- This situation will occur before kill mud reaches surface and care must be taken to ensure the kill mud circulation is completed.

For situations where meaningful drillpipe pressure is not available, the Dynamic Volumetric Method can be used (refer to Section 6 Subsection 4). This may be required when one of the following occurs:

- Drill bit is plugged.
- Drillstring has failed allowing communication between drillstring and annulus.
- Drillstring is off-bottom, causing drillpipe and casing pressures to read the same until the kick has migrated above the bit.
- Drillstring is out of the hole entirely.

9 HANDLING GAS IN THE RISER

When a kick is taken while drilling with a marine riser (particularly in deepwater) there is a possibility that the gas will have migrated or been circulated above the BOP stack before the well is shut-in. If this occurs, the choke manifold and MGS may no longer be available to control the flow rates when the riser gas reaches surface.

Special precautions and procedures are necessary to avoid the effects of the rapid expansion of this gas:

- An early flow check in the riser, immediately after shutting in the well, may indicate that bubbles are still rising and dissipating.
- The source of this flow may be due to a leak at the BOPs or gas expanding in the riser. Confirm that it is not the BOPs.
- Once all the small gas bubbles have become suspended in WBM, or dissolved in OBM a flow check in the riser will be negative.
  - This should not be assumed to indicate that there is no gas in the riser. Factors such as bubble fragmentation and suspension, which have little effect in a shallow water situation, begin to have a significant effect as the water depth increases.
  - Under certain conditions, the gas bubbles stop migrating. The gas is then held static by the yield stress of the mud, and must be circulated out of the riser.
  - Two factors that become significant in deepwater wells are gas bubble geometry and fluid rheology.
- Large bubbles can rise quickly through the mud (up to 110 ft/min 33 m/min) but they tend to break up and shed a trail of small bubbles as they rise. Small bubbles rise much more slowly and continue to leave a bubble trail until they are small enough to be held in suspension in the drilling fluid.
- The amount of gas left in the bubble trail can vary from 0.5% to 5% by volume of mud, depending on the yield point of the mud. For commonly used drilling fluids, it is typically between 1% and 2% but will be more if the fluid has high

or progressive gelling properties. This is a significant volume of gas that is within the accuracy of a well calibrated pit volume totalizer (PVT) system.

- There is approximately 4 times the mass of gas in a 15-bbls (2.4 m3, 2400 l) influx in 6000 ft (1800 m) of water as there is in a 15-bbls (2.4 m3, 2400 l) influx in 1500 ft (450 m) of water.
- Hardware is available to handle gas at the surface by allowing backpressure to be held on the riser.
- There is a possibility of creating a pressure inversion, where bottom hole pressure is brought to surface, if the gas migrates and is not allowed to expand while the annular element is closed at the surface.
- Riser is usually not designed to handle this pressure and could burst.
- Early kick detection is key to shutting in the well before the gas enters the riser. The use of advanced kick detection equipment is suggested. If possible, an additional sensor that can detect free gas in the annulus at or near the BOP stack should be installed.

9.1 VOLUMES AND FLOW RATES

Large amounts of gas above the BOP stack can rise rapidly and carry a large volume of mud out of the riser at high rates.

The key to managing gas in a riser is to avoid situations where large volumes of gas get above the BOP stack. If the volume of gas above the BOP stack is kept small by detection equipment and shut-in, then the gas can be safely handled at surface by allowing the gas bubbles to disperse and then controlling the rate that the mud is brought to surface.

- When the gas in the riser has been allowed to migrate and disperse to its maximum extent, the gas and liquid flow rates seen at the surface during circulation are minimized.
- Even if the gas reaches the surface without being circulated, the rates are minimized if the gas has been allowed to disperse.
- By circulating in stages, the expansion or dissolution of the gas can be controlled. There may be some mud loss through the overboard line with this approach, but with patience and control, all surface equipment will remain effective. Assuming that the speed of a bubble travelling upwards is 6000 ft/hr (1830 m/hr), at least 10 minutes migration time should be allowed for every 1000 ft (300 m) of riser.
- This allows the gas to disperse as much as possible, minimizing the gas and liquid rates seen at the surface.

- The use of a second PVT system on the riser should be considered while circulating the riser. This provides a better indication of an approaching large gas bubble and its associated liquid slug.
- However, if large volumes of gas have entered the riser, it will flow rapidly on its own and there will be no way to control it by adjusting the circulation rate. Then, the surface gas and liquid rates become very high, especially as the gas bubble reaches surface and the flow must be diverted overboard.

9.2 EQUIPMENT FOR HANDLING GAS IN THE RISER

The diverter system above the telescopic joint with two (2) overboard lines and a system to remove gas from large volumes of mud and return it to the mud system (such as a mud box on the overboard line) is preferred.

The diverter and overboard lines should be designed to handle high flow rates and be as straight as possible.

This system is not designed to choke or control high gas or liquid flow; rather, it is a system to keep combustible gases safely away from sources of ignition and to remove gas from the mud.

At any time, if there is a rapid expansion of gas in the riser, the diverter must be closed (if not already) and the flow diverted overboard.

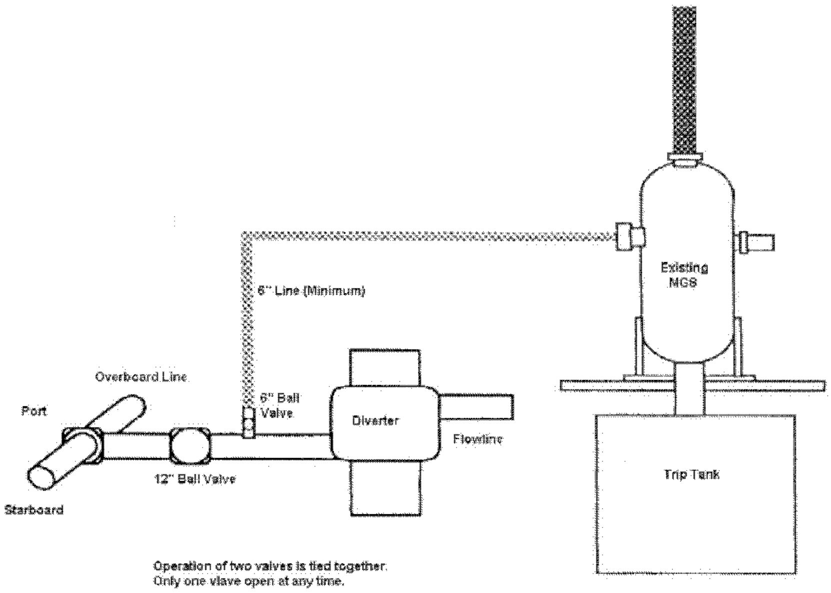
This is true for water based mud as well as for oil based mud. An alternate system using the MGS to remove gas from the mud is shown in Figure 8.4.12.

Either the mud from the riser or from the well can be circulated through the MGS to remove the residual gas (but only one at a time). Automatic valve switching is suggested such that the closing of the 12" valve and the opening and the 6" valve are coordinated.

An override switch should be available that will allow the manual opening of the 12" valve if the need arises. Also, automatic opening of the 12" valve should be tied to the separator pressure so that the separator rating is not exceeded or an automatic pressure relief bypass should be included.

A small volume circulating system should be isolated so that a volume totalizer can be used while circulating and monitoring the riser. This could be the trip tank if available.

Figure 8.4.12, Using Existing MGS to Clean Gas from the Mud



9.3 PROCEDURES FOR HANDLING GAS IN THE RISER

These procedures are to be conducted along with the shut-in procedures for Subsea BOP's as described in Section 5.

- Limit the volume of gas that may be taken above the BOP stack (early detection).
- If an influx is suspected, shut off the mud pumps. This will help avoid circulating the gas above the BOP stack.
- Shut-in the well as quickly as possible.
- Conduct a riser flow check. If the riser is flowing, divert the flow overboard. If so equipped, the flow can be diverted through a gas handling system or MGS.
- If the riser is not flowing or has stopped flowing, continue to monitor it for flow. Do not leave it unattended.
- If so equipped and if the MGS is not being used for the primary well control operations, the riser fluid may be circulated through the MGS at slow rates to remove the gas from the fluid.

- Circulate the riser at slow rates. Stop circulation and conduct a riser flow check after every 100 bbls (16 m_3) pumped or equivalent volume to +/- 250 ft (75 m) of riser.
- If gas is seen at surface, stop pumping and watch for flow. Allow the flow to deplete before continuing.
- If the flow rate increases, be prepared to open up the diverter line to send the mud overboard.
- Continue to circulate in stages at slow rate until the complete riser volume has been circulated.
- After killing the well and removing any gas trapped in the BOP stack, as described in Section 6, there is still the possibility that some gas trapped under the BOP stack may be released into the riser after opening the BOP. If this occurs, then the above procedures should be repeated.

9.4 RISER COLLAPSE

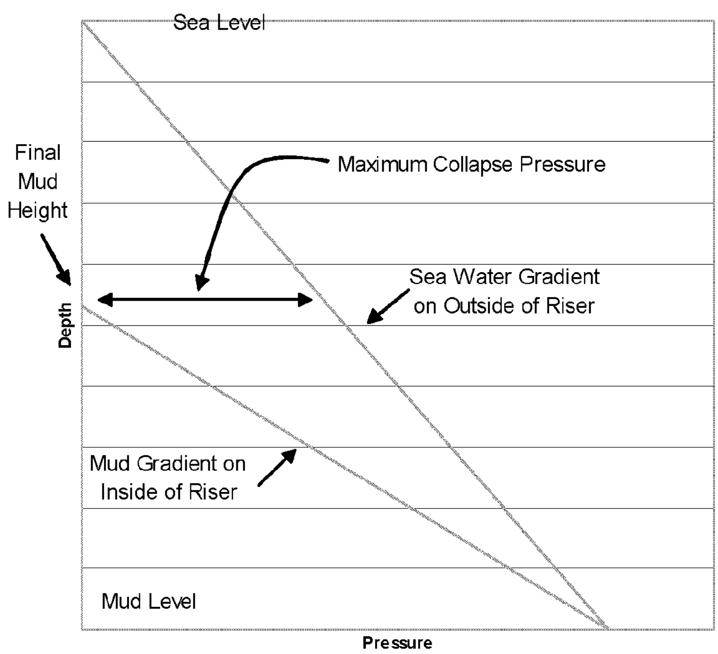
In deepwater the potential for riser collapse exists if the level of drilling fluid in the riser drops due to gas unloading the riser, drive-off, loss of circulation or accidental line disconnection.

Assuming the worst case to be during an emergency or accidental line disconnection, the pressure at the bottom of the riser would equal the seawater hydrostatic.

The fluid level in the riser would fall until this equilibrium is reached.

This is shown in the figure 8.4.13.

Figure 8.4.13, Riser Collapse Pressure Resulting From an Emergency Disconnect



The maximum collapse pressure that the riser would be subjected to resulting from an emergency disconnect can be found by the following equation:

$CP = SW \times 0.052 \times Dw \times (1 - SW / MW)$ ⇨ psi / ppg / ft

$CP = SW \div 102 \times Dw \times (1 - SW / MW)$ ⇨ kPa / kg/m^3/ m

$CP = SW \times 0.0981 \times Dw \times (1 - SW / MW)$ ⇨ bar / kg/l / m

Where:

CP = Collapse Pressure (psi, kPa, bar)
Dw = Depth of water (ft, m)
MW = Mud weight (ppg, kg/m^3, kg/l)
SW = Density of seawater (ppg, kg/m^3, kg/l)

A riser fill-up valve should be used if the collapse pressure could exceed the collapse pressure rating of the riser.

10 EMERGENCY DISCONNECT PROCEDURES AND CONTINGENCIES (DP RIGS)

During actual drilling or tripping drill pipe, if there is a loss of ability to maintain position, then it is necessary to be able to do the following:

- Hang-off the drill pipe on pipe rams
- Shear the drill pipe
- Effect seal on the wellbore
- Disconnect the LMRP
- Clear the BOP with the LMRP
- Dissipate any energy in the riser / riser tensioning system
- Safely capture the riser

The timing of these operations, particularly items 1-4 in the above list, is critical.

Each DP rig must have an emergency disconnect procedure specific to the rig. Emergency disconnect procedures must be posted in the Driller's house

MUX BOP controls used on DP drilling rigs use automated sequences to perform the disconnect operation. The disconnect sequences are normally initiated by dedicated buttons. Within the fleet there are variations in the number and function of disconnect sequence buttons. Many vessels have a single sequence button, labeled as "EDS" (Emergency Disconnect Sequence). Other vessels have both a "Preliminary Disconnect" and a "Final Disconnect" button. "Preliminary Disconnect" is a sequence that closes and blocks choke and kill valves and the middle pipe ram. Both the "EDS" and "Final Disconnect" are the full disconnect sequences. Many vessels have multiple EDS / FINAL DISCONNECT sequences, to take account of whether to use casing shear rams or specific combinations of other rams during different phases of drilling operations.

Each DP rig must have specific criteria that define the Yellow DP Alert and the Red DP Alert. Although disconnect criteria are stated in terms of offset from well centre, any of several factors could actually establish the maximum permissible excursion:

- Upper or lower flex joint angle
- Moonpool clearance
- Tensioner or telescopic joint stroke
- BOP, wellhead or surface casing strength

- Emergency disconnect sequence duration
- SSTT / DST operations
- Water depth
- Environment

1 GENERAL

A high pressure/high temperature (HPHT) well is one in which wellhead pressure could exceed 10,000 psi (68,950 kPa/689.5 bar) when shut-in on a full column of gas originating from the zone of highest pressure or, in which wellhead temperature could exceed 300°F (149°C) under conditions created by an uncontrolled flow from the zone of highest pressure.

HPHT wells are usually deep and their most notable characteristic is the narrow margin, or "Drilling Window", between formation pressure and fracture gradient. Because of the small tolerance between mud weights and the fracture gradient, circulating rates, ECD's and tripping speeds can become a significant cause of downhole problems (losses, swabbing etc.). A further complication is provided by the behavior of the mud under high pressures and high temperatures.

Drilling HPHT wells requires special planning, operating procedures and equipment, in particular when OBM is used. The following lists some of the most important precautions, procedures and equipment required that must be jointly addressed by the Operations Manager / Rig Manager Performance and the Operator before the HPHT drilling phase commences.

A bridging document will be developed in conjunction with the operator adopting these procedures and / or highlighting deviations from this document which have been agreed between Transocean and the Operator. This will then form the Joint Operations Manual which shall be the well/rig specific document for HPHT procedures.

2 PLANNING

A simulation can be made to estimate the maximum gas and fluid flow rates and wellhead temperature that could result from an uncontrolled flow from the zone of highest pressure through the open choke manifold.

At the beginning of the HPHT section, the maximum kick volume (kick tolerance) should be calculated to ensure that gas liberation rates at reasonable kill rates will not overload the MGS.

Specific plans must be made and written instructions given prior to spud, to all personnel, concerning non standard actions/procedures to be done to prevent or react to any well control problems.

The casing program must incorporate plans for a contingency casing string.
Planning to include a contingency for the drilling of relief well(s).

Surface BOP's to be fitted with casing rams to run production casing.

NOTE: VBR's may only be rated to 180°F (82°C) for continuous service.

3 PREPARATION

A Shut-in Circulating (choke drill) and Stripping drill must be held before drilling out of the deep intermediate casing. If possible, the drill should be held over a shift change, so that both crews can operate and become familiar with the equipment.

Conduct 'fingerprinting' tests before drilling out the casing shoe above the reservoir to establish the effect of temperature and pressure on the properties of the mud.

These include:

'trapped pressure' test to establish if pressure is trapped in the system following a hard shut-in after circulation and rotation.

'dummy' flow check to establish the thermal effects on flow back due to the mud column moving from a dynamic to a static state.

Record the drain down volumes, also the pit volume changes when the solids control equipment is started up or shut down. This is the amount of pit gain seen when circulation is stopped and the flowlines, troughs, shakers, etc., drain back to the active pits. Drain down tests should be done at both normal drilling circulating rate and at a reduced "well kill rate". The time taken for total drain down to occur should also be recorded. Weather criteria should be recorded on floaters during this drain down test.

Record and post this information in the Drillers doghouse and in the mud logging unit.

Slow Circulating Rates (SCR's) through the cement unit, the kill head, and the high pressure hose must be taken at least once after having set the deep intermediate casing.

Use the largest practicable jets in the bit to enable LCM pills to be spotted without plugging the bit.

4 OPERATING PROCEDURES

Consideration must be given to the following procedures (applicable only when drilling the HP zone) and specific instructions must be provided to the crew by the Senior Toolpusher.

4.1 MUD WEIGHT MEASUREMENT

There may be instances when narrow well control margins exist, such as minimal overbalance, and that in such circumstances certain items take on greater significance. An error of mud weight measurement of 0.005 psi/ft at 18,000 ft equates to 90 psi on bottom.

As such, when determining mud weights:

- Pressurized mud balances should be used. A 'master' balance, accurately calibrated in town, should be kept onboard for the sole purpose of providing a comparison for the balances in daily use. The 'master' balance could also be used for particularly critical mud weight checks. Any calibration adjustments to the balances in daily use should be logged.
- Adopt a standard method of measurement to eliminate any inconsistencies, human or otherwise.
- The mud balance calibration must be checked daily.
- The temperature of the mud returns must be constantly monitored.

4.2 KICK PREVENTION

If well stability is in question, or at the start of the HPHT section, limit ROP to ensure that there is no more than 1 connection gas in the annulus at any one time.
Once drilling in a continuous reservoir, and having established that a static overbalance exists at the top of the reservoir, the restriction can be lifted.

Additional points to be noted:

- Flow check all connections.
- All flow checks must have a minimum duration of 15 minutes and the drillstring must be rotated throughout when in open hole.

Note:

- When rotating the string in open hole beware of torque build up to avoid sticking the drill string
- For Floaters, care should be taken when flow checking as the well could be swabbed in or surged due to the rig motion.
- Mud flow from HPHT wells tends not to stabilize as quickly as other wells. This is due to effects of mud compressibility and temperature. The well may flow for many minutes, sometimes in excess of 30 minutes, due to these effects.

- A ported float valve should be run in all drilling assemblies. Core assemblies may also have a float valve installed if the drop ball-type retaining sub is installed
- Have a drop in sub in the string. Consider dropping the dart before tripping out (except for a wiper trip). Ensure that the dart will pass through the FOSV (full opening safety valve) and other components of the drillstring above the landing sub.
- To avoid differential sticking and to assist in breaking the gels, slowly rotate the drillstring prior to starting the pump(s).
- The Senior Toolpusher or his designee must be on the rig floor when POOH in open hole.
- Complete a bottoms-up circulation through the choke if a swabbed influx is suspected.
- If a drilling break occurs, the Driller must stop drilling immediately and verify if the well is flowing. The means of doing so is not restricted to flow checking on the trip tank and in order to minimize the size of the influx, methods can include finger-printing the flow back trend, direct observation of the mud level or by shutting-in immediately and observing for pressure build-up (see note below).

  If no flow is observed bottoms-up must be circulated with the last 3,000ft (1,000m) of annular volume below the BOP's routed through the choke. If the well has been shut-in, monitor pressures for a minimum of 5 minutes. If no SIDPP or SICP is recorded then open the well and flow check. Bottoms-up must then be circulated and routed through the choke as above.

  Note: the method used to verify the well is flowing is dictated by well conditions and should be agreed between rig management and the operator prior to spudding.
- Supervisory personnel to undergo special HPHT well control training course prior to spud.

- If the reservoir characteristics are unknown, limit coring to short intervals 30 ft (9 m) and circulate several times while POOH to limit risk of kick due to gas from the core coming out of solution.

4.3 KICK DETECTION

Detection methods and procedures described in Section 5 also apply to HPHT wells. However, it is recommended that additional equipment such as MWD tools be used to detect the top of the HPHT formation.

All efforts must be made to ensure that pit level indicators and flow sensors are properly installed and calibrated.

Use the minimum surface area in active pit volume to improve pit gain kick detection.

Transfers to and from the active system should not take place while drilling ahead in the HPHT section. The mud conditioning equipment should not be used while drilling through the reservoir.

Mixing of chemicals and/or barite in the active mud system while drilling is permitted if the volume change rate is less than 5 bbls. (0.8 m^3)/ hr.

All pit volume discrepancies must be investigated before drilling ahead.

If the normalized levels of background, connection or trip gasses rise above 100% of their normal values, circulate bottoms-up.

NOTE: Recognizing the signs of an influx and acting with the necessary speed to minimize it requires constant, accurate observation and recording of the mud volume, weight and relevant parameters. The resulting trends give the best picture of the well situation. Any variation can be identified, investigated and resolved before the situation deteriorates. The crucial feature is the "communication triangle" between the Driller, Mud Loggers and Derrick man/Mud Engineer in the mud pits.

It is essential that all information is regularly shared between the three points and that relevant personnel develop a good understanding of the current well condition. The Derrickman measures the pit volumes and records them, the Driller records the active volume on his drilling trend sheet along with any variation from the previous reading. The mud logging system is also constantly observed, therefore any variation from the established trend can be quickly investigated.

The Driller has full authority to flow check or shut in the well as he sees fit and is expected to fully investigate any occurrence which deviates from a stable trend.

4.4 SOLUBILITY OF GAS IN OBM

Swabbed kicks in an HPHT section should be seen on the surface.

Kicks caused by drilling into higher pressured formations in an HPHT section should be seen on the surface

"Low permeability" kicks may not be seen on the surface until the bubble point of the mixture is reached and gas comes out of solution. Refer to Section 4 Subsection 4 Item 2.

Gas solubility causes major concerns with regard to kick detection and gas expansion during the circulating out a kick.

Kick indicators such as pit gain or return flow will not be as pronounced when utilizing an OBM/SBM compared to a water based mud. The amount of gas that enters into solution with an OBM/SBM fluid is a function of its saturation point and the downhole conditions, and it will remain in solution until it reaches its Bubble Point. As the dissolved gas and OBM/SBM are circulated from the well, the pressure is reduced to below the bubble point and a rapid increase in fluid volume and return flow will occur. Understanding the bubble point of the reservoir fluids is important to be able to estimate the depth at which the gas will break out of solution. This is especially important in deepwater where the bubble point may be above the BOPs.

Most formation gases are soluble (as both liquids and gases) in OBM/SBM fluids. These soluble gases include methane, typical natural gasses, carbon dioxide, and hydrogen sulfide. These gases have minimal solubility in water base muds and brines.

4.5 HPHT DRILLING GUIDELINES

All drilling operations shall be conducted in such a manner that the possibility of an influx is minimized. Essential monitoring techniques and instrumentation will be available to rig site personnel. These personnel will be trained and practiced in the collection and interpretation of essential data related to kick prevention and detection. Furthermore, essential personnel will be instructed in the importance of data collection instrumentation and the need for its proper care and maintenance.

Consideration should be given the use of a working/drilling stand or working/drilling double for drilling the HPHT section.

Working Stand	**Working Double**
Saver Sub	Single Drill Pipe
Single Drill Pipe	FOSV
FOSV	Single Drill Pipe
Single Drill Pipe	FOSV
FOSV	Saver Sub
Single Drill Pipe	
FOSV	
Saver Sub	

The working stand will always have to be racked back for the connection; this will result in longer pumps off time.

The working double is the same as using a kelly, drilling in singles.

Prior to entering the sands, ensure that the amount of cuttings sample being circulated out at any time does not exceed the maximum desired penetration into the sand prior to coring or logging Do not restrict ROP; maintain constant parameters, as this is the best guide to entering the sand. Stop drilling and circulate as required.

Prior to making any flow check, pump back so that the lower FOSV is accessible at the rig floor.

When the well is not being circulated with the mud pumps, line up on the trip tank and circulate across the hole with the trip tank pump ensuring the alarms are closely set.

The trip tank is to be kept ½ full at all times and is to be flushed at the beginning of each shift (to coincide with obtaining SCRs) to displace its entire contents to the shaker header box. While the trip tank is being emptied the well needs to be checked with someone observing the flow line.

The temperature of the mud returns will be monitored at the header box at all times. Operations will be suspended if the mud return temperature exceeds the agreed temperature. The agreed temperature is usually based on the lowest rated elastomer in the well control equipment.

If the ratio between connection gas and background gas levels in the mud increase significantly, consideration will be given to increasing the mud weight.

Mud weight and temperature in and out will be recorded by the mud watcher using a calibrated pressure balance every 15 minutes and the Driller will be informed. See section 4.1 above with reference to measuring the mud weight correctly and accurately

Always attempt to establish rotation prior to circulation. The addition of ECD pressures on stationary pipe will increase the sticking tendency.

Rotation is essential to break the gels in heavy mud's, and avoid differential sticking. However, rotation does increase the ECD and it is advisable to carry out rotation checks at different gpm's and rpm's to establish the pressure increase.

The periods for which the drill string is left stationary should be measured in seconds not minutes. Keep the drill string moving to reduce the risk of differential sticking. Both rotation and reciprocation with the pumps on should be applied.

For Floaters - It may not always be possible to maintain the level of overbalance required to provide a positive riser margin. Closure of the BOP will entrap the hydrostatic head provided the BOP does not leak. However the Fact that a riser margin does not exist should be recognized and the contingency catered for. The long range weather forecast should be reviewed and predicted heave calculations made in conjunction with expected deck loads and other environmental conditions prior to drilling into the reservoir.

4.6 KILL PROCEDURES

All influxes (or suspected influxes) must be assumed to be gas until they are circulated out.

Control slow circulation rate in order not to exceed surface equipment capacity; in particular, procedures must be prepared to cover the situation where the mud gas separator capacity or the down stream choke temperature limits are reached or likely to be reached. Gas expansion downstream of the choke could lead to low temperatures causing blockages in the choke manifold or mud gas separator.

If the formation pressure is very close to the fracture gradient use the Driller's Method to circulate out a 'drilled' influx and increase the mud weight incrementally with succeeding circulations.

Consider Bullheading for influx volumes greater than a specific value.

When BOP's are equipped with lower kill valves, these valves should not normally be used for any reason other than emergency kill.

Using them in static mode to monitor annular pressure is permissible but not recommended.

Kill sheets will be updated each time SCR pressures are taken, after every 500 ft. drilled in the HPHT zone and every time the mud weight is changed.

5 EQUIPMENT

5.1 AUXILIARY EQUIPMENT

A 15,000 psi (103,000 kPa/1030 bar) working pressure kill pump must be available, capable of slow circulation rates of as little as 0.5 bbls/min. (0.08 m^3/min., 80 l/min) and preferably have a remote control adjacent to the choke console at the Driller's station.

A 15,000 psi (103,000 kPa/1030 bar) working pressure kill line shall be installed between the kill pump and the rig floor.

A 15,000 psi (103,000 kPa/1030 bar) working pressure kick assembly [comprising kelly cock(s) and side-entry sub] must be made up and pressure tested and must be easily accessible.

All primary pressure containment equipment must be selected for H_2S service.

The Choke and Kill manifold must have an antifreeze injection facility.

The Choke and Kill manifold should have mud temperature measurement probes upstream of chokes to help evaluate wellhead temperature (unless BOP's are equipped with the same) and down stream of chokes to help assess risk of hydrate formation with remote reading at choke panel.

The Choke and Kill manifold should be fitted with high pressure overboard lines [5000 psi (35,000 kPa/350 bar) minimum rating] and remotely operated valves to open same and close the mud/gas separator line.

The kill and choke lines will be flushed from the top every 24 hours if displaced to mud. This will prevent plugging due to barite settlement.

For Floaters, the kill and choke lines should be flushed from the top every 12 hours (if displaced to mud) or more frequently as the mud cools rapidly and gels.

Inspection of key well control components, e.g., auto chokes and target flanges, will be undertaken after prolonged circulation through the chokes whether routine or in any well kill situation.

A dedicated stripping tank of 5-7 bbls (0.8-1.1 m^3) capacity is recommended.

The MGS must be equipped with a means of monitoring pressure (normally a low pressure differential sensor, typically 20 psi/1.4 bar with a remote reading at the choke panel).

The MGS pressure and temperature measurement system and alarms must be function tested weekly.

The MGS must be flushed daily if it contains mud.

The facility to heat and to inject low pressure mud into the MGS is a useful option.

The MGS will be lined up as per the rig's instruction. The Driller will function test remote actuated valves from the choke manifold buffer chamber at the start of each shift and will pre-select the downwind line. Log on IADC report.

An alarm if fitted on the choke manifold buffer chamber, will be set to alarm prior to reaching its rated working pressure. This will alert personnel and allow manual operation of the by-pass system to protect the MGS inlet from excessive pressures.

MGS design and size must be reviewed to ensure adequate capacity for reasonable circulating rates and kick sizes (refer to Section 10 Subsection 12). An additional separator must be provided if necessary. **NOTE: 8" to 10" (203 mm- 254mm) diameter vent lines with 15 to 20 ft (4.5-6 m) mud seal have been found necessary in some instances.**

To monitor casing, wellhead and BOP wear, ditch magnets should be used. The ditch magnets should be cleaned and inspected at regular intervals not exceeding 12 hours of rotation. A base line casing caliper log should be run prior to drilling out of the casing set above the HPHT formations. If excessive metal particles are collected by the ditch magnets and/or abnormal wear on the drillpipe wear bands are noted, the casing should be re-pressure tested and/or further casing caliper surveys run. The casing should be pressure tested when the BOP's are pressure tested as per Section 9.

If a liner is run or the open hole plugged back the casing must be tested.

The rig's own gas and H_2S detectors will be cleaned and inspected weekly. All detectors will be tested prior to drilling out the casing above the HPHT Section and the critical detectors every two weeks thereafter. The Mud Loggers' gas and H_2S detectors will be tested prior to drilling out the casing above the HPHT Section and weekly thereafter.

All rig, mud logging and cement pump instrumentation will be systematically cross calibrated at each BOP test. This will include the pump pressure, pump strokes, pit volumes and choke and kill gauges. Record cross calibration checks on the IADC report.

Two Gray type non-return valves will be kept on the rig, one to be on the rig floor.

Two 15,000 psi (103,000 kPa/1,030 bar) working pressure FOSV's should be kept on the rig floor with operating wrench readily available for immediate use and crossovers available to adapt to each thread type in the drill string.

All FOSV's in the kill assembly, working stand or working double & emergency stab valves should have the same size operating wrench to avoid delays in closing the FOSV.

A ball drop circulating sub should be run in each BHA, above any core barrel, turbine, PDM or MWD tool. In a conventional BHA the ball drop circulating sub will be installed as close to the bit as possible. As an alternative a shear out type circulating sub may be run if deemed suitable.

A Hydril drop in dart sub will be run in each string above the HWDP and have sufficient ID for any required tools to pass. The wireline retrievable drop in dart of the correct size will be kept in the Driller's doghouse.

At the start of each shift the bulk lines from the storage silos should be purged to ensure they are clear and to confirm air dryness.

5.2 BOP STACKS

The minimum BOP standards required by Transocean for surface and subsea stacks are described in Chapter 9.

HPHT recommended standards:

Surface BOP's on Jack-up or platform rigs - a minimum of one (1) 10K psi annular preventer and four (4) 15K psi ram type preventers should be utilized.

Subsea BOP's - a minimum of two (2) 10K psi annular type preventers and four (4) 15K psi or greater ram type preventers are required.

HPHT BOP seals need not be used if it can be proven that under maximum expected BOP temperatures the temperature rating of the seals will not be reached.

Choke and kill lines must be flushed at least once per tour in the HPHT section of the well.

6 MATERIALS

The temperature rating of all BOP elastomers exposed to well fluids shall be higher than the maximum anticipated temperature at the wellhead/BOP stack for continuous exposure of at least the expected duration of the well. The elastomers shall also be certified to withstand the anticipated peak temperature/pressure for at least one hour. (The peak temperature is the temperature that could be reached when uncontrolled flow through the choke line has to be allowed for one hour).

If BOP temperatures are estimated or measured to be approaching maximum rating of the elastomers, either the fluid flow rate should be reduced or the well shut-in.

A sufficient quantity of kill weight mud to kill the well and maintain a full wellbore until additional mud material can be delivered should be kept on board until after the well is plugged and abandoned or the completion phase is finished.

STOCKS OF MUD MATERIAL (BARITE, BENTONITE, CHEMICALS), LCM MATERIALS AND CEMENT MUST BE MAINTAINED TO THE LEVELS REQUIRED

BY THE DRILLING PROGRAMME. EFFORTS SHOULD BE MADE TO KEEP THESE LEVELS AS CLOSE TO MAXIMUM AS POSSIBLE DURING THIS STAGE OF THE WELL.

7 HPHT TRIPPING PROCEDURES

Tripping is an operation where the risk of influx is high, therefore it should be performed only when necessary. The well should be planned to minimize the need to trip, e.g., BHA and bit selection should be designed for longevity rather than outright ROP.

NOTE: These are supplementary to 'standard' tripping procedures (refer to Section 4 Subsection 4 Item 1 Tripping Practices).

When not in use, the trip tank must be kept half full at all times and flushed during each shift.

The slug volume should be limited to 12-18 bbls (2-3 m^3).

Two independent calculations of swab/surge speed must be made (e.g. Mud Loggers, Mud Engineer, Client's Drilling Engineer) and a print-out of the more accurate schedule provided to the Driller.

Hole fill must be monitored and recorded by both the Driller and the Mud Loggers. Any discrepancies must be flow checked immediately.

Before **the first trip to surface after drilling into the HPHT zone,** make a short trip to gauge the hole's tendency to swab (refer to Figure 8.5.1).

Circulate at least bottoms up to:

a) Condition mud to reduce swab/surge pressures.

b) Remove any entrained gas or cuttings from the system.

Flow check.

Do not pump the DISV dart.

Do not drop a survey barrel.

Do not slug the pipe.

POOH at the 'swab reduction speed'.

Flow check after pulling the required number of stands.

RIH to bottom at the 'surge reduction speed'.

Circulate bottoms-up. Check for swabbed gas.

7.1 POOH TO SURFACE (REFER TO FIGURE 8.5.2).

Flow check.

Pump out to inside the shoe.

Flow check.

Pump dart (if required).

Pump slug and measure mud returned.

Continue to POOH.

Flow check mid way out of the hole and when the bottom hole assembly (BHA) is just below the BOP.

7.2 RIH TO BOTTOM

RIH at ‘surge reduction speed’.

Break circulation just inside the shoe.

Continue RIH to bottom.

Circulate bottoms-up before drilling ahead and, if high gas levels have been observed, the last 3,000 ft (915 m) below the BOP’s must be circulated through the choke.

If unable to pull out of the hole without swabbing, then pumping out of hole must be considered:

Do not pull faster than the annular velocity of the mud that is being circulated.

After pulling the required number of stands, whether into the shoe or not, attempt to POOH without pumping.

If the hole is still swabbing, continue pumping out of the hole, checking every 10 stands for swabbing.

After being able to pull 10 stands without pumping, flow check for 15 minutes.

RIH to bottom.

Circulate bottoms-up and check for gas. If it is suspected that an influx has been swabbed in, circulate bottoms-up through the choke.

Pump out of the hole to the point where previously tripping without pumping was possible.

Continue to POOH at ‘swab reduction speed’.

8 HPHT CORING GUIDELINES

Coring will only take place if it is safe to do so. Consult with shore-based operations. Do not proceed with coring unless there are explicit instructions to do so.

Special precautions should be implemented when coring high pressure zones. In order to maintain an acceptable trip margin (in the region of 0.5 ppg), the mud weight may be raised to compensate for the calculated increased swabbing potential as a result of having the core barrel in the hole. If there is a weak formation interval and the mud weight cannot be raised to provide the acceptable trip margin, then coring should not be attempted.

The inner barrel shall be designed to prevent trapping pressure (relief valved or fluted). A drop ball sub will be installed immediately above the core barrel.

A float valve will be installed above the drop ball sub, and with a circulating installed above.

It is possible that gas being released from the core when tripping out could expand rapidly in the top section of the hole and produce a sudden flow. This will be difficult to observe on the drillpipe because of the slug and the resultant dry pipe. Be particularly vigilant when tripping in the top section of hole and be prepared to shut in.

The core barrel will be pulled to approximately 2000 ft. below the BOPs, the BOPs closed and circulation will be established through the drop ball circulating sub (after dropping the ball) and routed through an open choke and mud gas seperator. Circulation will continue until no free gas is observed in the mud. The core barrel will be pulled to within 1000 ft. of the BOPs and the procedure repeated. For floating operations in deeper water the circulation of any trapped core gas may require the use of the Diverter system to divert gas released above the BOP.

A minimum of 15 minute flow check will be made prior to pulling the core barrel through the BOPs.

Be aware of the possible presence of trapped gas beneath the float valve.

Check for the presence of H2S in the core prior to handling at surface.

Coring rate should not be restricted in reservoir sequences where there is a regressive pore pressure gradient or where it can be demonstrated that any fluctuations in the gradient will still be less than the pore pressure gradient at the top of the reservoir.

The maximum core barrel length should be agreed for the first run and thereafter increased if no problems have been encountered.

The length of the core barrel will be well specific depending on formation and temperature. The bottom hole temperature will extend the inner barrel and may cause it to jam.

Circulating rates may need to be reduced when circulating with the core barrel.

The stuck pipe model of Esso has shown that beyond a differential pressure of 800 psi, the chances of getting differentially stuck increase rapidly.

Recommend drilling 20 ft into a reservoir to ensure adequate penetration of formation to be cored.

9 WIRELINE LOGGING (MDT LOG / FLUSHING RFT)

It is recommended to conduct a wiper trip to flush out accumulated gas in the wellbore if the logging needs to be continued beyond 2-3 days in the HPHT section of the well. Where narrow well control margins exist, the gradient and volume of formation fluids being sampled / flushed by Formation test tool into the well bore must be monitored. The implications of excessive continuous flushing should not be under estimated. As such, the decision to run the formation test tool must be subject to a formal written risk assessment.

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Figure 8.5.1, Tripping Out Procedure # 1

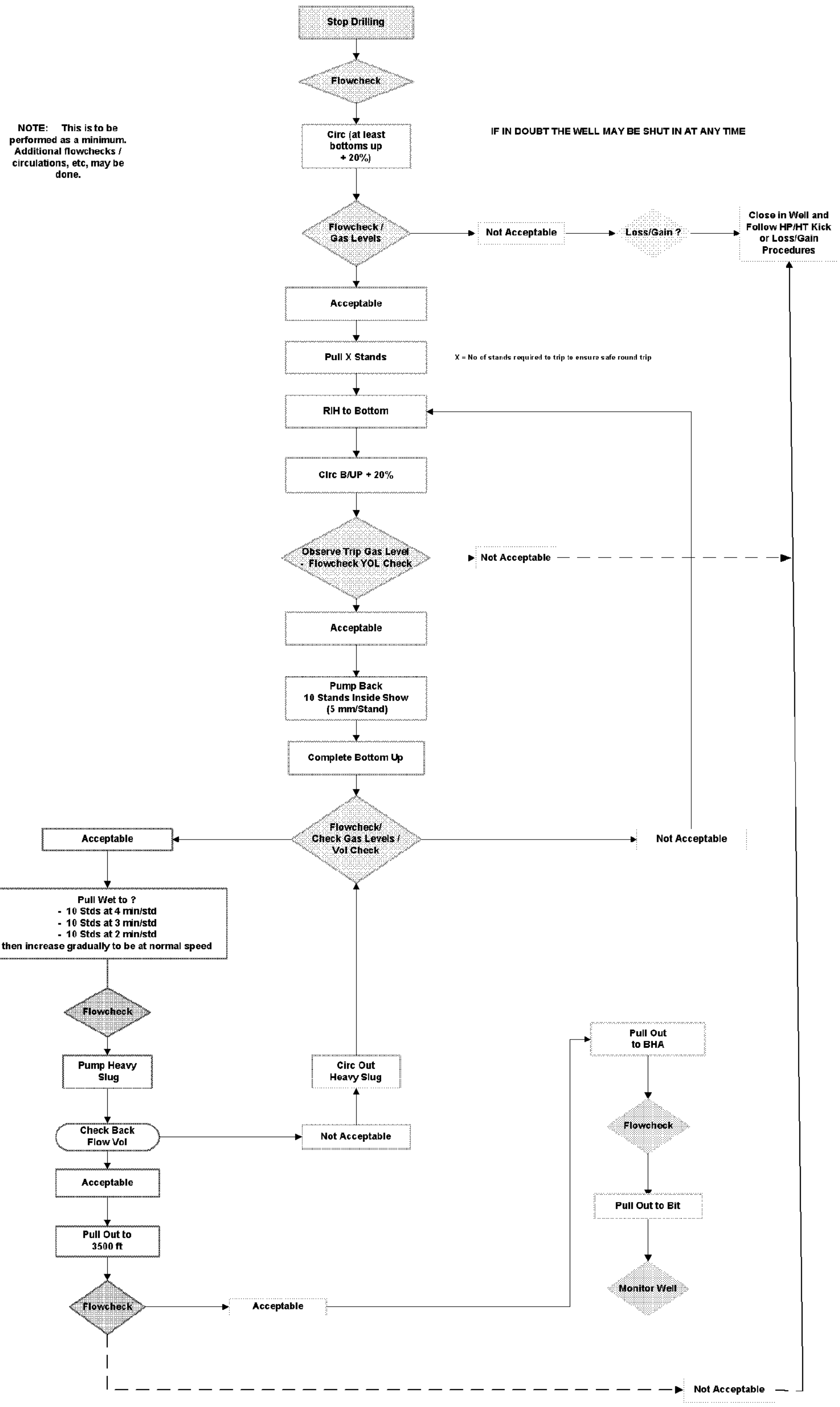
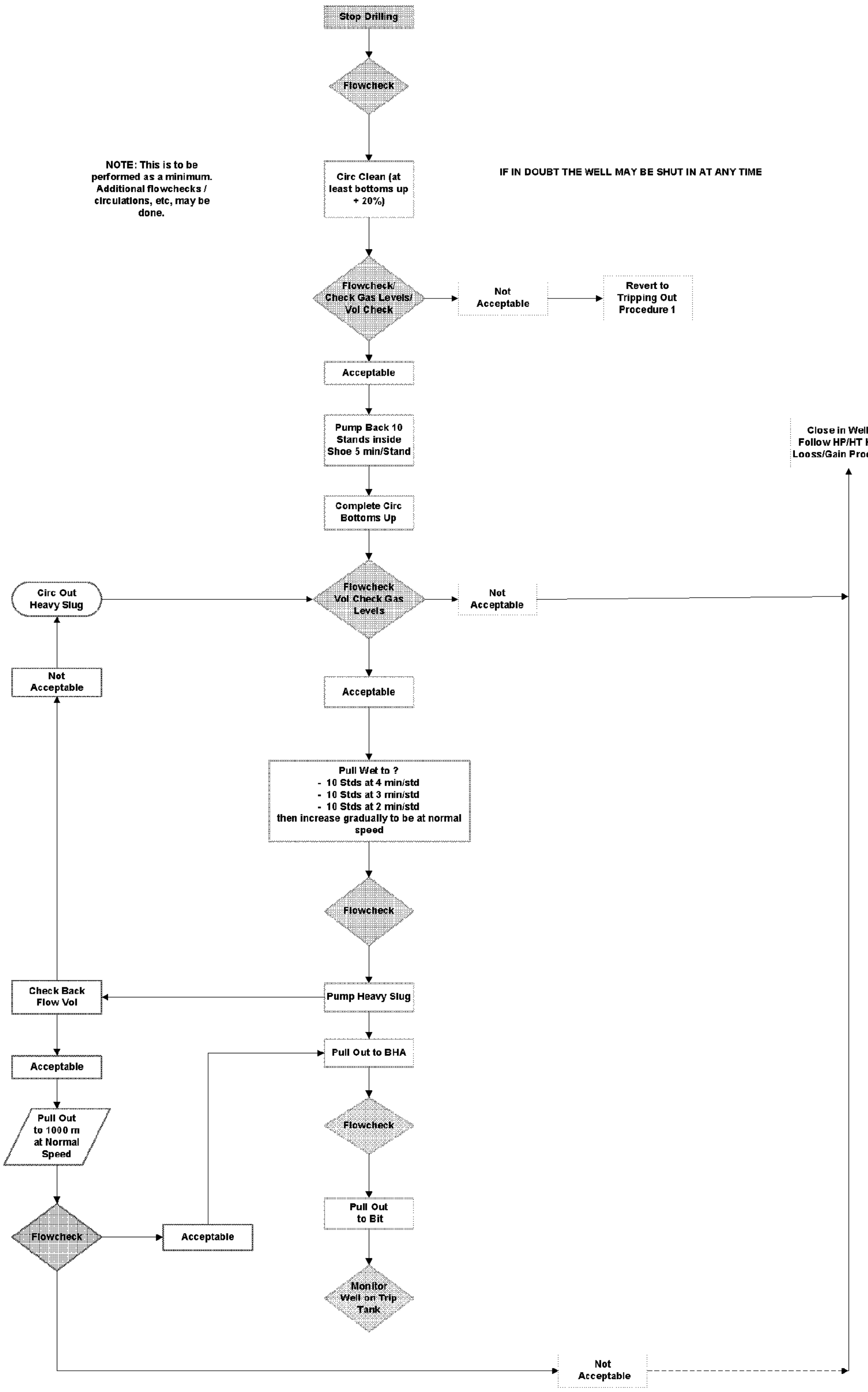


Figure 8.5.2, Tripping Out Procedure #2



1 GENERAL

'Slim hole' refers to hole sizes of 4-3/4" in diameter or smaller and drilled by jointed pipe. Annular volumes in these wells can be 1/5th or less than those of 'conventional' wells with the result that the small drillstring/hole clearances produce higher annular pressure losses (and hence higher ECD's) while drilling, so increasing the risk of lost circulation. In addition, these reduced clearances are more likely to induce swabbing when POOH and, should a kick be taken, it will occupy a significantly greater height in the annulus, resulting in higher shut-in casing pressures.

The greater influx height results in higher choke pressures at surface to maintain constant bottom hole pressure. Higher choke pressures are applied directly to the casing shoe as the influx is circulated out.

THE RESULT IS THAT SLIM HOLE WELLS HAVE A MUCH SMALLER KICK TOLERANCE COMPARED WITH CONVENTIONAL WELLS.

For the same reason, early and rapid shut-in (i.e. hard shut-in) on slim hole wells is critical to reduce the kick volume. By this, the related choke pressures and the chances of losing returns during subsequent kill procedures are reduced.

2 PRINCIPAL CAUSES OF KICKS

2.1 INSUFFICIENT MUD WEIGHT

The increased ECD can mask the penetration of an over-pressured section and prevent a kick as long as the pumps are running. When the pumps are shut off, the loss of ECD reduces the hydrostatic pressure and a kick can occur. Similarly, the high rotational RPM common to slim hole drilling can cause a significant increase in annular pressure losses and ECD. Slowing down or stopping pipe rotation will reduce ECD and can allow a kick to occur.

2.2 LOST CIRCULATION

The higher ECD's can cause lost circulation in areas where conventional drilling practices and densities would not. If these result in massive losses and loss of hydrostatic, then a kick could be taken.

2.3 SWABBING

The hydrostatic pressure in the wellbore will always be reduced to some extent when the drillstring is being pulled from the hole. This is particularly so in slim hole wells where the annular clearance between the drill collars and wellbore is smaller making swabbing a common cause of kicks in slim hole.

3 KICK DETECTION AND PREVENTION

3.1 DIFFERENTIAL FLOW

The use of highly sensitive instrumentation on the standpipe and flow line (in order to measure differential flow) will identify an influx more quickly than monitoring the mud pits for indications of a gain.

3.2 FLOW CHECKS

If there is a positive indication of a kick occurring, dispense with a flow check and shut-in the well immediately in order to limit the size of the influx.

3.3 DRILLING BREAKS

Drilling breaks must be treated as potential kick situations. After each drilling break, the well should be shut-in immediately after circulation is stopped and observed for any pressure build up.

3.4 DRILLING CONNECTIONS

When the rotating and circulating frictional losses are removed from the annulus during a connection, the probability of an influx or kick occurring will be increased. Unfortunately, this is also the time that tank levels fluctuate most making detection difficult. To increase the detection capability and reduce potential kick sizes, all connections in the reservoir sections should be flow checked in the following manner:

- Prior to making the connection and with the pumps still running at full circulating rate, stop rotating the string and observe for a gain.
- If no gain occurs, over a period equivalent to that of a conventional flow check, shut down the pumps. Observe the well a second time.
- Proceed with making the connection.

3.5 CIRCULATING BOTTOMS-UP

When circulating bottoms-up, the well must be closely monitored for any kick indications (e.g. increased mud returns, pit level increase). At the first positive indication, stop circulating and shut-in the well.

3.6 PUMP PRESSURE INCREASE/PUMP STROKE DECREASE

In slim hole wells, providing the underbalance is sufficiently high, an increase in pump pressure may be seen due to the rate of flow of the kick into the well producing an increase in the annular pressure loss. Such an indicator should be carefully assessed as it could also be generated by hole pack off problems such as mild wellbore collapse or rapid accumulation of drilled cuttings. However, the latter causes will be accompanied by a noticeable increase in torque.

3.7 PRE-RECORDED INFORMATION (SCR'S)

A modified set of SCR readings must be taken for all slim hole wells prior to drilling out the surface casing shoe and before tripping into the hole each time the bit, BHA, or nozzles are changed.
Use the following procedure:

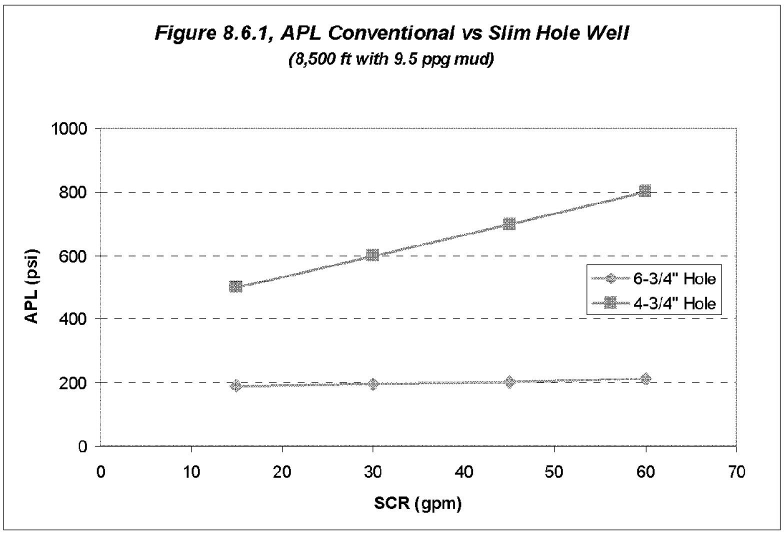
- Make up and run in the bit and first stand of drill collars and, using the appropriate cross over, install the topdrive/kelly.
- Circulate at three SCR rates (e.g. 15, 30, 45 SPM) and record the standpipe pressures. These values will be called the surface equipment and bit friction pressure losses (SPL+ BPL). The annular pressure loss along the stand of collars will be negligible. Record these SCR readings on the Annular Pressure Loss (APL) Calculation Sheet that can be found in Appendix 8. The SCR must be chosen to kill the well that results in an APL less than that required to cause formation breakdown and lost returns.
- Take a second set of SCRs at the same pump rates once the bit is on bottom and record these on the APL Calculation Sheet. Another significant reason for using a low SCR in slim holes is that the extremely small annulus results in much more rapid changes in influx height and annular pressure requiring rapid adjustments of the choke to maintain constant bottom hole pressure.
- Calculate the APL using the following method. Assuming the APL is distributed evenly from the surface to TD, start with the highest SCR and calculate the ECD at the shoe and at TD or any known weak zone. If there appears to be a chance of formation breakdown, go to a lower SCR rate.
- Select the fastest SCR that will not cause well problems. If the one selected is not the slowest possible, and choke operational control is difficult to maintain, consider changing to a lower rate. If the SCR-APL does not pose significant risk of formation breakdown or is less than 100 psi then a conventional well control method can be used.

3.8 DETERMINATION OF ANNULAR PRESSURE LOSSES

The primary complication in circulating out an influx in a slim hole well is the fact that the APL is high even at slow circulating rates.

Figure 8.6.1 below illustrates the difference in APL between a 4¾" slim hole well and a 6¾" conventional well design.

Figure 8.6.1, APL Conventional vs Slim Hole Well



The determination of annular pressure losses at the reduced circulation rates is critical for two reasons. First, if the APL is above the threshold value that will cause lost circulation while circulating out a kick, it will have to be accounted for in the well control process. This is achieved by slightly modifying either the Driller's Method or the Wait and Weight Method in such a way that the APL is accounted for by the choke adjustment. Much the same way CLFL's are accounted for in deepwater drilling.

4 SLIM HOLE WELL CONTROL METHODS

To accommodate the unique features of slim hole well designs we are required to slightly modify the two circulating methods to arrive at:

- The Slim Hole Wait and Weight Method.
- The Slim Hole Driller's Method.

4.1 SLIM HOLE WAIT AND WEIGHT METHOD

The slim hole Wait and Weight Method includes additional steps to account for higher APL's. As with the conventional Wait and Weight Methods, the starting point on the pump drillpipe pressure schedule is the ICP. The drillpipe circulating pressure will decline on a straight line basis as the kill mud is pumped down the pipe. After the kill mud reaches the bit, the circulating pressure will start to rise.

The fundamental difference between a conventional and the slim hole Wait and Weight Method is the magnitude of the final pressure rise due to the APL. This APL is much higher in the slim hole case and must be accounted for. The significant increase in drillpipe pressure is accounted for by using slightly modified names for the process concerned. The term FCP_1 is used to identify the pressure that will be maintained as the kill weight mud exits the bit and rises up the annulus. FCP_2 will be the pressure that will occur when kill mud reaches the choke.

The procedure is as follows:

After the well has been secured and pressures have stabilized:

1. CALCULATE THE KILL MUD WEIGHT:

   KMW (ppg) = [SIDPP (psi) ÷ 0.052 ÷ TVD (ft)] + OMW (ppg)

   KMW (kg/m^3) = [SIDPP (kPa) x 102 ÷ TVD (m)] + OMW (kg/m^3)

   KMW (kg/l) = [SIDPP (bar) ÷ 0.0981 ÷ TVD (m)] + OMW (kg/l)

   Trip Margin will not be included in the calculation for kill weight mud. The main reason for this is to avoid unnecessary additional wellbore pressure that could result in formation breakdown.

2. CALCULATE THE INITIAL CIRCULATING PRESSURE:
   ICP = (SCRP + SIDPP) – APL

3. CALCULATE FINAL CIRCULATING PRESSURE (ONE):
   $$FCP_1 = (SCRP - APL) \times \frac{KMW}{OMW}$$

4. CALCULATE FINAL CIRCULATING PRESSURE (TWO):
   $$FCP_2 = SCRP \times \frac{KMW}{OMW}$$

5. CALCULATE SURFACE TO BIT STROKES:

$$\text{Strokes} = \frac{\text{Drill string Volume}}{\text{Pump Output}}$$

6. CALCULATION TIME TO PUMP FROM THE SURFACE TO THE BIT:

$$\text{Time} = \frac{\text{Total strokes from surface to bit}}{\text{Strokes per minute}}$$

7. Once the calculations are completed, fill out a kill sheet by plotting drillpipe pressure versus pump strokes.
   - Plot ICP at left of graph.
   - Plot FCP_1 at right of graph.
   - Connect points with a straight line (assuming a vertical well).

4.1.1 KILL MUD TO THE BIT

Once the kill sheet graph has been completed and the mud weight has been raised to the desired value, prepare to circulate through the choke; open choke manifold valve(s) upstream of choke (or downstream if applicable), zero stroke counters, ensure good communications between choke operator and pump operator.

Once pressures have stabilized, bring the pump to kill rate speed while reducing the choke pressure by an amount equal to the previously determined annular friction pressure losses (APL). (Less CLFL for subsea BOP's.)

Once the pump is up to kill speed and the pressures have stabilized, record the actual circulating drillpipe pressure.

If the actual circulating pressure is equal to, or reasonably close to the calculated ICP, continue pumping and adjust the pressure according to the drillpipe pressure schedule. If the actual circulating pressure is significantly different from the calculated ICP, stop the pump, shut the well in, and investigate the reason. Ensure there is no trapped pressure.

4.1.2 KILL MUD TO SURFACE

After the kill mud reaches the bit and starts to fill the annulus, the drillpipe pressure should be held constant at FCP_1 using choke adjustments. If the pressure rises close to maximum values then consideration should be given to gradually reducing the pump speed to a lower circulating pressure or until such time the choke is wide open. Thereafter the circulating pressure will rise automatically to a final circulating pressure FCP_2.

Once the uncontaminated kill mud returns are at surface the well must be flow checked through the choke before opening the BOP's. Note that during the circulation, there will come a time when the kill mud reaches sufficient height in the annulus that the hydrostatic pressure added to the APL will balance the formation pressure and the choke will be in the fully open position. This will occur before kill mud reaches surface and care must be taken to ensure the kill mud circulation is completed.

4.2 SLIM HOLE DRILLER'S METHOD

4.2.1 FIRST CIRCULATION

Once the pressures have stabilized, prepare to circulate through the choke; open choke manifold valve upstream of choke (or downstream if applicable), zero stroke counters, ensure good communications between choke operator and pump operator. Bring the pump to kill rate speed while adjusting the choke in a way that reduces the casing pressure by an amount equal to the previously determined annular friction pressure (APL) losses. This choke adjustment should take place over the same duration of time it takes for the pump to get up to the SCR and for the outflow to stabilize.

When kill rate speed is established, the choke operator must switch to the drillpipe gauge and hold this pressure (calculated ICP) constant until the influx is removed from the wellbore. Note the casing pressure just prior to shutting down pumping. This casing pressure should stay constant, if all the influx was removed during the first circulation, until the kill mud reaches the bit using the drillpipe pressure schedule.

When all influx is circulated out, stop the pump and close the choke to check the SICP and SIDPP. At the end of the first circulation, the SICP and SIDPP should be the same and equal to the initial SIDPP. The active mud system should be adjusted to the proper kill mud weight.

4.2.2 KILL MUD TO THE BIT

Bring the pump to kill rate speed while adjusting the choke in a way that reduces the casing pressure by an amount equal to the previously determined annular friction pressure (APL) losses. This choke adjustment is identical to that used when initiating the first circulation.

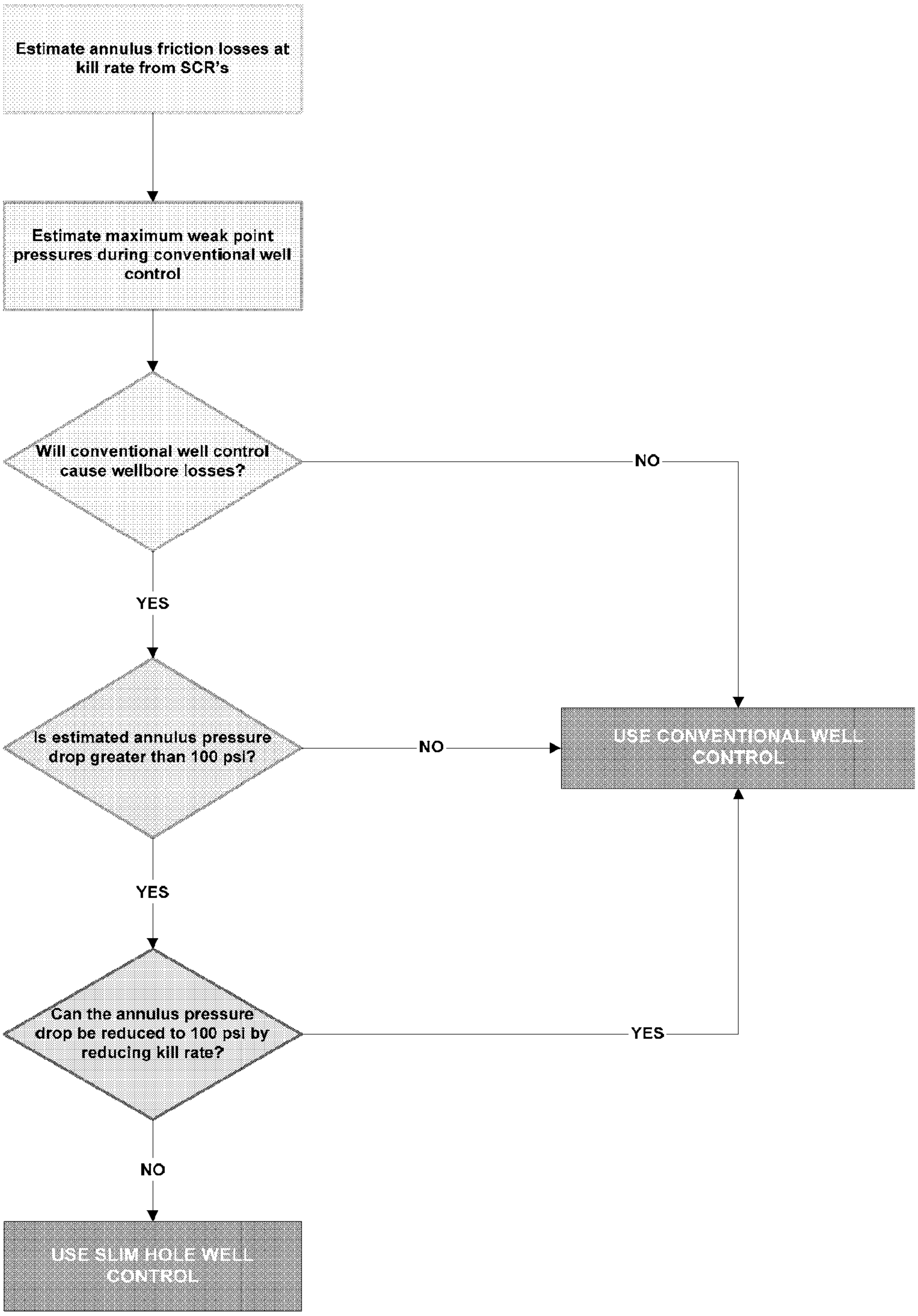
When kill rate speed is established, switch to the drillpipe gauge and follow the drillpipe pressure schedule until heavy mud reaches the bit.

This will occur while dropping from the initial circulating pressure (ICP) to FCP_1.

4.2.3 KILL MUD TO SURFACE

When the kill mud enters the annulus, hold the drillpipe pressure constant until the choke is full open. Continue circulating until heavy mud reaches the surface. The drillpipe circulating pressure will increase to the same FCP_2 as was determined for the Wait and Weight Method and the choke pressure will steadily decrease as the kill mud replaces the original mud in the annulus.

Figure 8.6.2, Decision Tree for Slim Hole Well Control



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1 GENERAL

In 'conventional' drilling one of the principal objectives is to prevent a kick being taken by means of primary well control. In Under Balanced Drilling (UBD) the well is encouraged to flow by reducing the hydrostatic pressure of the drilling fluid to below that of the formation pressure.

Among the benefits derived from UBD are:

- Reduced 'skin' damage and reservoir impairment.
- Increased production rates.
- Increased ROPs.
- Increased bit life.
- Reduced drilling problems such as lost circulation, differential sticking, high torque and drag.

2 UBD WELL CONTROL

Primary well control is not provided by the drilling fluid but by a Rotating Head or Rotating BOP (RBOP) and associated pressure control equipment.

The fluid influx is controlled at all times from the time it enters the wellbore until it exits at the surface by regulating the flow rate and thus the BHP. Well control is an integral part of the drilling operation and not as separate and distinct an issue as it is in overbalanced drilling.

Wells drilled under balanced or while flowing must have surface and well control equipment specially designed for these operations.

In almost all UBD operations, there must be available a means of returning the well to a static condition (i.e. killing the well and circulating out any formation kick). The means of doing so will depend on how the under balance was originally achieved.

2.1 FORMATION PRESSURE BELOW NORMAL PRESSURE GRADIENT

For the well to flow, either gas lift or foam must be used to reduce the annular hydrostatic pressure. Parameters can be adjusted as needed and the well can be killed easily by reducing the gas injection rate.

Down hole conditions must be controlled to ensure circumstances do not arise where sections of the wellbore are subjected to higher pressures than they can withstand, which could result in an underground blowout.

2.2 FORMATION AT NORMAL PRESSURE GRADIENT

The well should flow if light fluids such as diesel, base oil or crude are used as a base for the drilling fluid (within the obvious constraints on pumping flammable fluids).

Killing the well in an emergency can be achieved by having a suitable kill fluid ready to pump into the well. Again, the pressures encountered are not likely to cause problems within the wellbore.

2.3 FORMATION ABOVE NORMAL PRESSURE GRADIENT

The well will flow simply by decreasing the fluid density below that which would normally be used in overbalanced drilling. However, there may be a risk that sections of the wellbore may experience higher pressures than they can withstand if the flow rate and BHP are allowed to fluctuate significantly.

Killing the well will require a higher density fluid and circulating a kick from the well would entail similar risks as those for overbalanced drilling. The use of UBD for wells of this nature should not be considered unless there is a high degree of certainty relating to the pressures that are likely to be encountered and the overlying formation strengths.

Common to all these cases is the possibility of wellbore collapse. Some formations are highly unstable (e.g. sloughing shales) and require hydrostatic pressure to maintain their stability.

Should UBD be attempted in such conditions, there is a significant risk of losing the well and the drilling assembly. Also, depending on the pressure characteristics of the well, wellbore instability could contribute to an underground blowout or undesired cross-flow between formations of dissimilar pressure.

2.4 TYPES OF DRILLING FLUIDS/GASES USED IN UBD

- Low density mud or brine
- Air, gas (exhaust or natural gas), nitrogen (cryogenic or membrane separation)
- Foams
- Aerated fluids

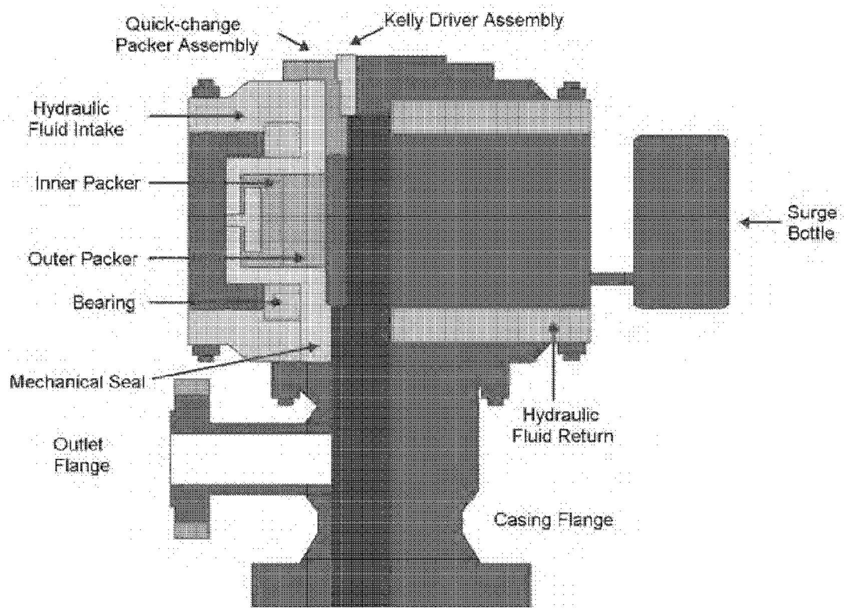
3 EQUIPMENT

The selection of equipment will depend on the magnitude of the surface pressures expected, the method of pipe rotation (i.e. top drive or rotary table), the nature of the reservoir fluids to be encountered and the type of drilling fluid/gas to be used.

Specialized surface equipment and procedures will be required for handling hydrocarbon returns from the well while drilling. Depending on the fluid/gas used, the equipment spread could consist of:

- Compressors and boosters.
- Rotating BOP/Rotating Head/Diverter Preventer. [All of the above are terms used to describe a rotating, low pressure (700-2500 psi/4800-17200 kPa/48-172 bar WP) device used in drilling operations to seal around the drillstring above the top of the BOP stack.]
- At least two (2) non-ported floats or flapper valves to prevent backflow from the well should be installed near the bottom of the drillstring while drilling under balanced.
- PWD sub to determine bottom hole annulus pressure.
- Special bits and motors (depending on fluid/gas used).
- Choke manifold.
- Under balance drilling manifold.
- Two-, three- or four-phase Separators or Gas busters.
- Skimmer.
- Diverter (blow down) line and flares.
- Solids control equipment.
- Surface instrumentation.
- Bypass lines and bleed off lines.
- Fire stop and fire floats.
- Chemical (mist, foam) injection system.

Figure 8.7.1, Rotating BOP



The BOP stack as a minimum must comply with the requirements set out in Section 9 of this manual and, in addition, may consist of:

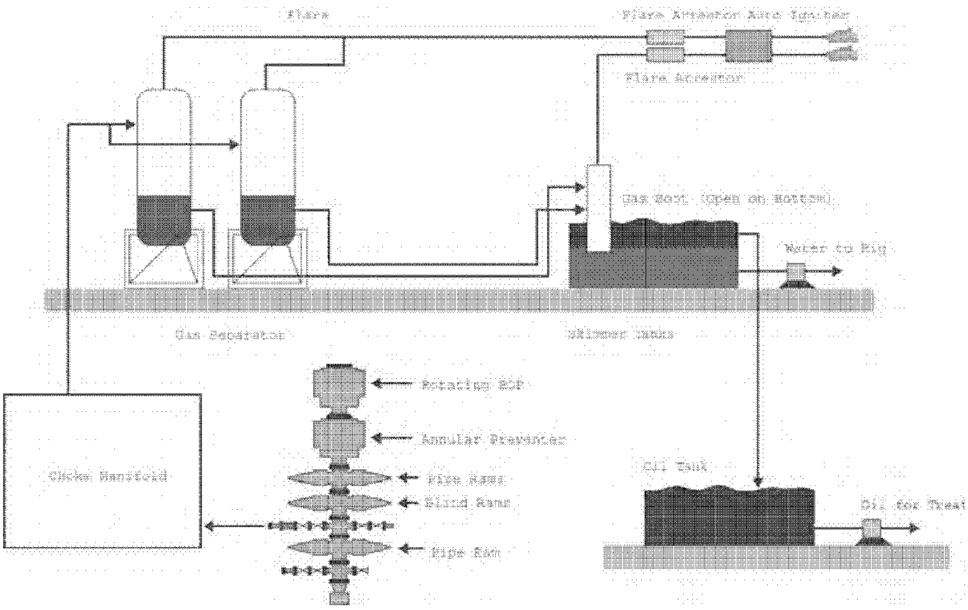
- RBOP and diverter line with remotely controlled valve(s).
- The capability to bleed off pressure to a flare or through a manifold in the event of a diverter line obstruction or any other operation that requires by-passing the Separator.
- The capability to equalize pressure between the diverter line on the RBOP to below the lowest ram type preventer.
- The accumulator system used to control the RBOP will be independent of the rig's standard accumulator system.

4 OPERATIONAL PROCEDURES

No primary well control equipment (preventers other than the RBOP) will be used for stripping, snubbing or drilling.

When the top float sub is at the rotary table, there must be procedures and equipment for safely venting trapped gas from below the float before removing it from the drillstring. A pressure indicator, with a readout visible at the Driller's station, should be installed below the blind/shear rams to monitor wellhead pressure while the drillpipe is out of the hole. For tripping under balanced, BHAs should be designed to take into account the need to strip some of the components through the RBOP in order to close or open the blind/shear rams.

Figure 8.7.2, UBD Surface Equipment



5 GENERAL SAFETY POINTS FOR UBD

The nature and complexity of maintaining adequate control of wellbore conditions requires a thorough understanding of the factors which influence the flow and pressure of formation fluids in a wellbore. This is necessary to ensure that changing wellbore or fluid conditions are detected early enough to allow appropriate responses that will maintain the wellbore conditions within the design limits.
The following factors apply to the majority of UBD operations:

- A comprehensive risk/failure analysis must be developed, concerning the specific conditions of the well to be drilled under balanced.
- From the analysis, specific contingency plans should be developed for emergencies relating to equipment failure or unexpected pressures.
- All BOP and flow equipment should be tested prior to going under balanced and on a periodic basis thereafter.
- Procedures should be developed for routine well kill operations as well as emergency well kill responses.

- Frequent emergency drills should be conducted.

6 PROCEDURE FOR KILLING AN UNDERBALANCED WELL

It may be necessary to kill the well if the volume of formation fluid/gas being produced is greater than the surface equipment can handle.

This procedure outlines the steps to be taken when circulating kill fluid in a well and is not intended to be a procedure that covers all well control situations.

Upon detection of excessive production:

- Pick up off bottom.
- Stop pumping.
- Stop gas lift to the well.
- Shut-in the well with diverter line auto valve, open the HCR valve on choke line.
- Record shut-in casing pressure every minute until it stabilizes.

NOTE: It will not be possible to 'read' the SIDPP due to the two flapper/float valves in the BHA unless the procedure in Section 5 Subsection 4 Item 4 is used.

- If the bit is in open hole, the string must be kept moving at all times. If in cased hole, the bit should be kept below the deepest Gas Lift Mandrel.
- Line up the returns to the choke manifold to route the flow through the choke to the Test Separator via the Sand Separator.
- Confirm the pump is lined up to the crude oil in the Low Pressure Separator. Ensure crude temp is >20°C.
- Bleed back the SICP to 200psi (this is "normal" flowing pressure + 50 psi safety factor).

Open the choke and bring the pump up to the Slow Circulating Rate (SCR) speed and pressure while manipulating the choke to maintain a constant SICP.

- When the pump is up to speed switch to monitoring the DPP and maintain the pressure at this value.
- With circulation established, start pulling back into the sanctuary of the cased hole while keeping the bit below the lowest Gas Lift Mandrel.

- Circulate the complete annulus volume (open hole volume + drillpipe/production completion annulus volume) and closely monitor the returns to the Test Separator (it is unlikely that any liquid returns will appear at surface).
- Shut down the pump and close the choke. If the influx has been circulated out, SICP should equal zero. Bleed off any trapped pressures through the choke to the Test
- Separator. Monitor Test Separator for well fluids.
- Close choke and monitor pressures for further build up. Bleed off any additional pressure through choke until there is no further build up.
- Close in choke and blow down Test Separator.
- Flow check the well for a minimum of 15 minutes, or until certain that the well is dead.

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1 GENERAL

Lost circulation occurs when whole mud is lost to a formation and should be distinguished from the small loss of volume attributable to the deposition of filter cake or mud not recovered from drilled cuttings at the shakers.

If there is a strong possibility of a kick resulting from lost circulation, it may be prudent to install a circulating sub in the BHA to enable the coarsest LCM to be pumped down the drillstring without plugging the jets or the pipe.

The main hazards of lost circulation are:

- The loss of hydrostatic head may result in a kick.
- The drop in mud level prevents accurate measurement and monitoring of the fluid level in the hole.

2 TYPES OF FORMATIONS IN WHICH LOSSES CAN OCCUR

2.1 UNCONSOLIDATED FORMATIONS

These occur mainly at shallow depths and normally consist of sands but can also occur in gravel, shell beds or reef deposits. The rate of loss is normally low but can increase if left untreated.

2.2 HIGHLY PERMEABLE/LOW PRESSURE FORMATIONS

These are mainly sands and are often depleted reservoirs. The loss of mud to these formations of high permeability requires that the intergranular passages be of a sufficient size to allow whole mud entry and that the hydrostatic pressure exerted by a column of drilling fluid is greater than the formation pressure.

2.3 NATURAL FRACTURES

Natural fractures can occur in many rock types (particularly limestone) and requires only that the hydrostatic pressure of the drilling fluid exceeds that of the fluid within the formation. Initial losses may be gradual but if drilling continues and more fractures are exposed, losses can be total.

2.4 CAVERNOUS FORMATIONS

These normally occur in Limestone and Dolomite formations and usually result in sudden and complete losses.

3 CAUSES OF LOST CIRCULATION

Induced fractures can occur when the drilling operation creates conditions where the pressure on the formation exceeds the fracture gradient of the rock. Research suggests that as much as 90% of down hole losses are induced.

3.1 EXCESSIVE MUD WEIGHT

The weight should be maintained no higher than the safe minimum to hold back formation pressure and stabilize the wellbore. Drilling into a normally pressured zone with a mud weight required to control an abnormally pressured zone or raising the mud weight to control formation pressure can exert sufficient force to induce losses.

These losses can vary from seepage to total and where a reduction in mud weight is possible and practical, such a reduction may cure the losses.

3.2 HIGH ECD'S

While the hole may remain full when the mud is static, the pressure losses associated with circulation up the annulus may be sufficient to induce mud losses to the formation. It may be possible to cure these losses by reducing the mud weight, lowering the rheology, reducing the pump rate or a combination of all three. Should any of these remedies be used, the impact on hole stability and hole cleaning should be taken into account.

3.3 POOR FILTRATION CONTROL

A high water loss may result in a thick filter cake building up against the formation. This reduces annular clearances, leading to higher velocities for a given flow rate and an increase in the ECD. In extreme cases bridging can occur.

3.4 PRESSURE SURGING

Pump surging can produce pressure increases equivalent to 1.0 ppg (120 kg/m^3, 0.12 kg/l) or more.

Rapidly lowering drillpipe or casing can result in a pressure peak high enough to break down the formation.

3.5 CIRCULATING/CEMENTING CASING

Down hole losses often occur while circulating or cementing casing due to the higher pressures that result from the reduced annular clearance. In addition, cement slurry densities may exceed the fracture pressure of the formations in which the casing is being cemented.

3.6 DISTURBING A CUTTINGS BED

In deviated wells combination Hi-Vis/Low Vis pills, with significantly differing rheologies, may be pumped to improve hole cleaning when drilling. It is possible for these cutting beds, when disturbed, to slide down the hole, packing off the drillstring.

3.7 HOLE ENLARGEMENT

Hole enlargements can reduce the mud velocity to the point that cuttings are no longer transported out of the well but accumulate and bridge where the hole size is normal, resulting in pressure surges.

3.8 ANNULUS LOADING

Losses often occur (particularly in large diameter, surface hole sections) due to cuttings build-up in the annulus. This could be due to high ROP's and/or poor hole cleaning and results in increasing the EMW in the annulus.

3.9 HOLE IN THE CASING

A hole in the casing can lead to a loss of circulation by subjecting a formation, previously protected by the casing, to a mud weight that exceeds its fracture gradient.

If any loss of circulation is encountered, the Toolpusher and the Operator Representative must be informed and the options discussed before any action is taken.

4 SEVERITY/CATEGORIES OF LOSSES

4.1 SEEPAGE LOSSES (UP TO 20 BBLS/HR (3M^3/HR))

This takes the form of very slow or sometimes undetectable losses to a permeable formation. Occasionally this may be due to filtration losses due to poor fluid loss control. Tripping is permitted with seepage losses.

NOTE: The identification of seepage losses may be confused with the removal of cuttings from the mud at the shakers. If hole stability is critical, the losses may have to be cured.

4.2 PARTIAL LOSSES (20-50 BBLS/HR (3-8 M^3/HR))

Because these losses are more severe, the potential problems with the re-supply of stocks become more important.
Tripping is not permitted with partial or severe losses.

4.3 SEVERE LOSSES (50-500 BBLS/HR (8-80 M^3/HR)) AND COMPLETE LOSSES (500 BBLS/HR (80 M^3/HR) - NO RETURNS

IF COMPLETE OR SEVERE LOSS OF RETURNS OCCURS, IMMEDIATELY PUMP THE LIGHTEST FLUID AVAILABLE DOWN THE ANNULUS, RECORDING THE VOLUMES REQUIRED TO FILL THE HOLE.

The hydrostatic pressure that the hole will support should be calculated.

Because of the reduction in hydrostatic head the hole must be monitored very carefully.

When drilling top hole sections with high ROPs, overloading the annulus may cause complete losses. If this is the case, consider pulling out and circulating in stages to clean the hole.

5 CLASSIFICATION OF LCM

CONFIRM THAT THE DRILLING PROGRAMME SPECIFIES THE TYPE AND ADEQUATE QUANTITY OF LCM TO BE HELD ON BOARD FOR EACH HOLE SECTION.

Conventional lost circulation materials are supplied in three grades - Fine, Medium and Coarse.

- Fine - under most circumstances will pass through the shaker screens and remain in the mud system.
- Medium - will be screened but will not plug jets or MWD tools.
- Coarse - may plug off everything except open-ended drillpipe.
- Other specialist materials are graded according to particle size or the mesh opening through which they will pass.

5.1 COMMON TYPES OF LCM:

- Fibrous - Materials that have little rigidity and are thought to mat across the surface or within a formation that is taking fluid.
- Granular - Materials, capable of taking mud, that have rigidity and thus can bridge and wedge either at the face of or within formations.
- Flaked - Materials with a scaly, layer like appearance which may have limited or no rigidity.

5.2 OTHER LCM:

- Shear activated gels - these cross-linked polymers are easy to pump (no plugging) and set-up once sheared through, for example, bit nozzles.
- Specialist cements - easier to place than normal cement and less prone to flash setting/planting drillstrings.

6 RESTORING FULL CIRCULATION

6.1 SEEPAGE/PARTIAL LOSSES

- Drill ahead carefully while adding fine lost circulation materials to the mud.
- Reduce the mud rheology values and circulation rate and reduce the pressure on the loss zone.
- After all other factors have been assessed, consideration should be given to reducing the mud weight.

6.2 SEVERE/TOTAL LOSSES

- Fill the annulus with a measured volume of light mud or water.
- Pump a fluid of an equivalent density to the composite fluid column in the annulus, mixed with lost circulation material. Ensure this mud weight will control all other exposed formations.
- In case of massive losses, continue to fill the hole with seawater while deciding upon the best corrective action.

6.3 SEALING THE LOSS ZONE

If circulation cannot be restored by using Lost Circulation Material (LCM), try to seal the loss using “soft plugs” such as salt gel, diesel oil - bentonite ‘gunk plugs’, etc. Alternatively, the use of a cement plug may be considered.

After sealing a loss zone, consider setting the casing when a non-permeable zone is penetrated.

6.4 BALANCED PLUG

A balanced plug should have the correct volume of spacer pumped behind the slurry. This ensures the hydrostatic pressure in the annulus is balanced with the pipe before the pipe is pulled out of the plug. If it is decided to squeeze the plug, 2 bbls (0.3m^3) of mud should be pumped down the pipe, the BOP closed and then squeeze pressure applied on the annulus below the rams. Balanced plugs may enter the formation under the hydrostatic pressure of the fluid column alone or may need to be squeezed. Depending on squeeze pressure, reverse circulate the pipe contents if possible, after pulling out of the plug.

To calculate the volume and displacement of a balanced plug:

- Calculate the plug volume from the height it will occupy in the open hole.
- Calculate the spacer ahead and spacer behind the plug.
- Calculate the volume of fluid required to displace the plug and spacers into their final position.
- Calculate the height of the plug before the pipe is withdrawn.
- If spotting cement through a bit, do not use the balanced plug technique. The bit should be tripped into the casing and the non-balanced plug technique used.

6.5 NON-BALANCED PLUG

Where the loss zone depth is known with certainty then the pipe can be placed approximately 100 ft (30m) above it. The slurry is displaced to the end of the pipe and the BOP is closed. For a downhole mixed plug, pump simultaneously down the annulus and pipe at 2 bbls/min (300 l/min). For a spotted plug pump the slurry out of the pipe plus 5 bbls (0.8m^3) excess, then pump down the annulus only.

6.6 REASONS FOR FAILURE TO CURE LOST CIRCULATION

- Unable to identify the depth of the loss zone.
- Type and concentration of lost circulation material not matched to the severity of the loss.
- Technique not matched to the severity of the loss.
- Insufficient information.
- Unbalanced columns in cementing operations.

7 DRILLING BLIND

In certain circumstances it may become necessary to drill ahead without any returns at the surface, i.e. 'drilling blind'.

DRILLING AHEAD WITHOUT MUD RETURNS IS FORBIDDEN UNLESS APPROVED BY THE BUSINESS UNIT DIRECTOR OF OPERATIONS PERFORMANCE.

This may be required if all other attempts to drill as described above have failed. Once the decision to drill blind or use a floating mud cap has been made, the main objective will be to set casing in the first competent formation penetrated.

Although no cuttings will be obtained while drilling blind, the casing seat can be located by logging, MWD tools or by keeping up a penetration log while drilling ahead. The hole has to be logged frequently, for example every 100 ft or whenever the penetration rate suggests a formation change. Once a competent formation has been identified, the new formation has to be penetrated by at least 50 ft to set and cement the next casing string successfully.

8 LOST CIRCULATION DECISION ANALYSIS

Figures 8.8.1, 8.8.2 and 8.8.3 can be used as a guide in determining the most suitable method of dealing with a lost circulation problem.

9 LOSS / GAIN PROCEDURE

A loss/gain situation, sometimes referred to as supercharging or ballooning shales, is used to identify a type of false indication of a kick. It is caused by the loss of drilling fluid to the well, either into a fracture in the formation or into an expanding well bore (plastic shales), and the subsequent return of the fluid when the pumps are turned off, giving indications of a kick.

A loss/gain situation is difficult to positively identify prior to circulating bottoms up and many wells have been shut in, the mud weight increased and the "influx" circulated out. In this scenario, increasing the mud weight compounds the problem.

The following are some of the indicators which help to identify that a loss/gain scenario may be occurring:

- Drilling fluid has been lost during the current drilling operations
- Pit gain occurs after turning the pumps off

- The shut in drillpipe and casing pressures approach each other
- The shut in drillpipe pressure must always be less than or equal to the annular friction loss.

It is, however, worth noting that all the above can occur in a true kick situation as well.

If a loss/gain situation is suspected, then bottoms up should be circulated using the drillers method to control the bottom hole pressure. The returns at bottoms up should be analyzed for evidence of influx from formation fluids. If a loss/gain scenario has been positively identified, this may take several bottoms up with the well open and no indication of formation fluids, then the recommended procedure is to minimize the forces acting on the well bore to eliminate losses by reducing some or all of the following:

- Mud weight
- Flow rate
- RPM
- Rheology

If hole conditions do not allow this, then consideration should be given to running casing to isolate the problem formation(s).

Figure 8.8.1, Losses While Drilling

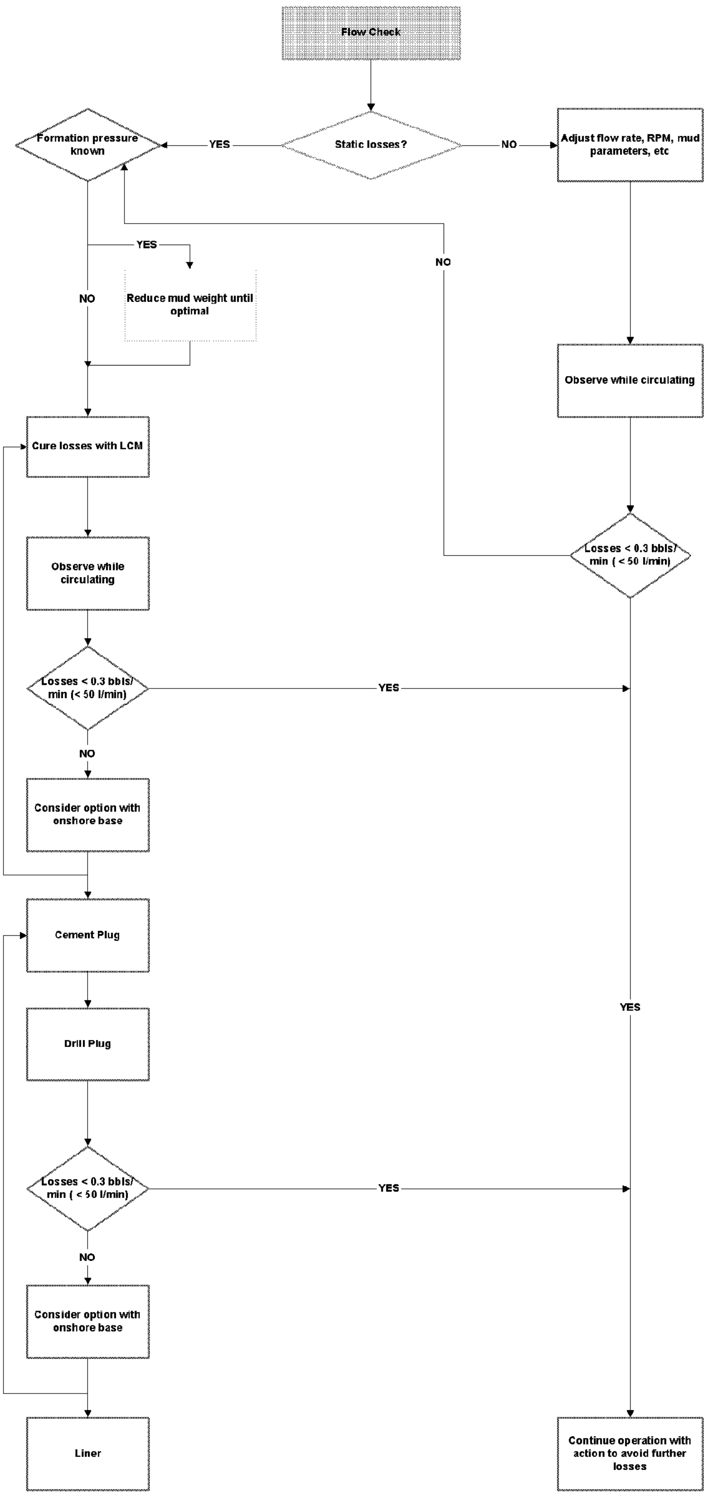

Figure 8.8.2, Losses While Tripping in Hole

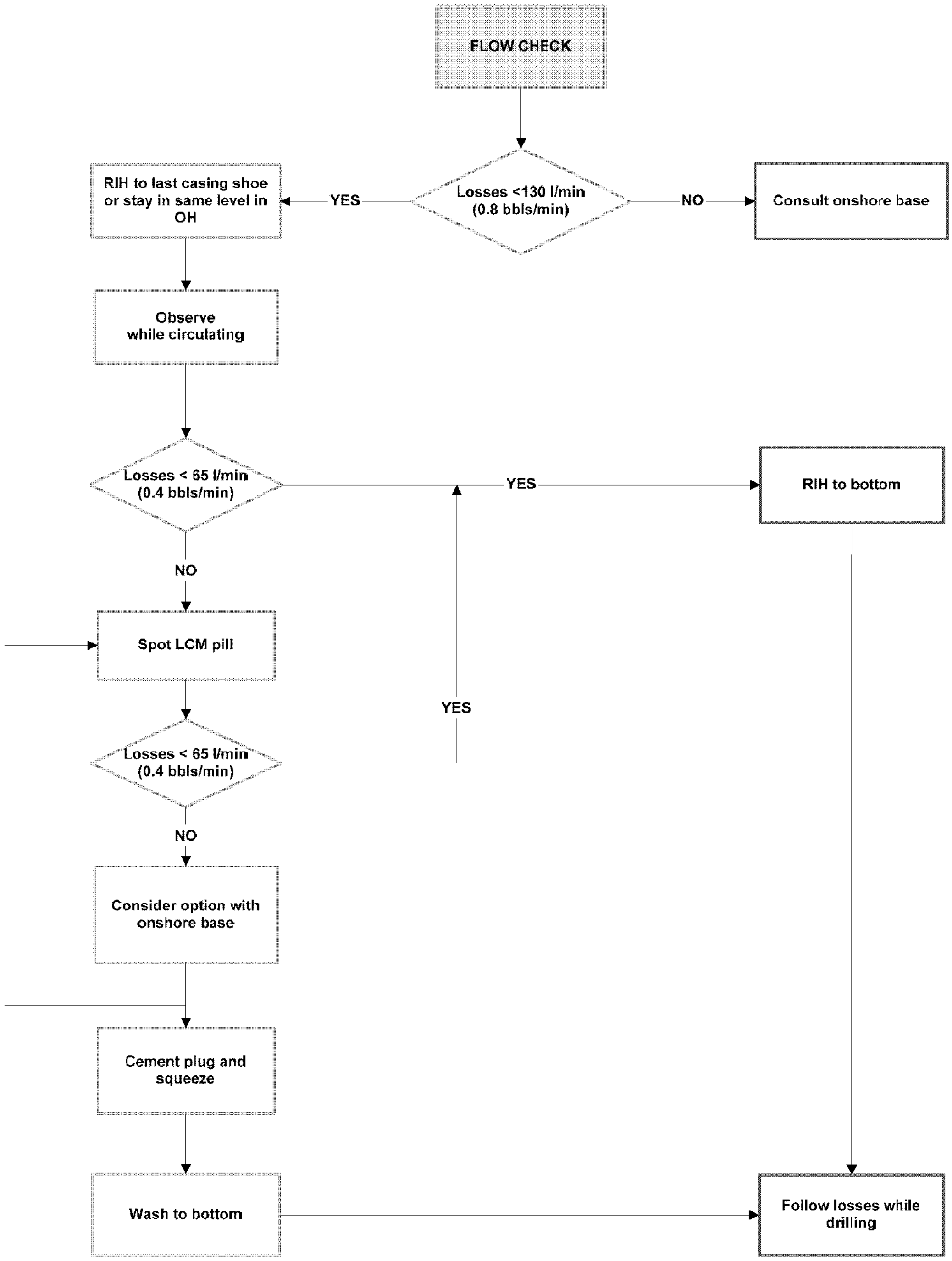

Figure 8.8.3, Complete Loss Circulation – Options

TYPE OF LOSS	SYNTHETIC OBM	RESERVOIR EXPOSED	INDUCED LOSS	OPTIONS (Refer to option descriptions)
TOTAL (no returns)	YES	NO	YES	Requirement: ALL CASES Fill hole with light fluid
				Reduce mud weight Chemical block/cement
			NO	Reduce mud weight Chemical block/cement
		YES	YES	Reduce mud weight Chemical block/cement Address reservoir requirements
			NO	Reduce mud weight Chemical block/cement Address reservoir requirements
	NO (WBM)	NO	YES	Requirement: ALL CASES Fill hole with light fluid
				Reduce mud weight Chemical block/cement
			NO	Reduce mud weight Chemical block/cement
		YES	YES	Reduce mud weight Chemical block/cement Address reservoir requirements
			NO	Reduce mud weight Chemical block/cement Address reservoir requirements

KEY INFORMATION TO BE CONSIDERED

1. Potential Well Control Ramifications
2. Formations Exposed
3. Suspect Loss Zone
4. Potential BHA Limitations

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1 COMPLETIONS

Completions can be split into three main categories.

"Open Hole" or "Barefoot" completions are used in areas where the formation is strong and consolidated and will not breakdown or collapse when the well is brought into production.

"Perforated Cemented Casing / Liner" completions are used to produce from selective pay zones or for isolation of unconsolidated formations which may collapse under production conditions.

"Uncemented Liner / Screen" completions are used to hold back any unconsolidated formations but do not isolate any distinct formations from each other.

When installing completion hardware (tailpipe, packer, extension joint, safety valve, etc.) into any of the above types of well, it is necessary to adhere to the Transocean procedure and maintain a minimum of two independent tested barriers at all times. This can be achieved by utilizing the Drilling BOP, a known monitored column of fluid, cemented and tested casing / liner, or tested mechanical barriers (plugs, packers, etc.).

The preferred method of testing barriers is in the direction of flow from the well. This cannot always be achieved (i.e. open hole below barrier) and therefore, depending on the type of equipment installed, a test from above may be accepted.

Six basic types of new build completions can be designed. These are:

- Oil producer
- Gas producer
- Water injector
- Gas injector
- Oil producer that later becomes a water injector
- Gas producer that later becomes a gas injector

Depending on the specific environment (H_2S, CO_2, wax, scale, hydrates, etc.), the completion will be designed for the expected production / injection profile of the field and based on the completion design (above), may include such items as side pocket mandrels, expansion joints, ESD pumps, nipples, etc.

Specific details or completion components will not be addressed in this manual.

It is the responsibility of the Toolpusher to ensure that cross-overs are available on the drillfloor for all completion components to enable the stabbing of a kelly-cock and IBOP.

2 WELL INTERVENTION / WORKOVER

2.1 WELL HANDOVER STATUS

Prior to any well being entered or worked on, a full formal handover status of the well must have been received and reviewed. This should include, but not be limited to:

- Type of well to be worked on.
- The reason why the well requires intervention or workover.
- Updated completion schematic (including dimensions and material specifications of all equipment installed, open / closed status of valves, shear rating of extenda joints, size of any orifice valves installed, last Hold Up Depth (HUD), number of clamps, date the well was last worked on, etc.).
- Xmas tree valve leak-off / pressure test data (pressures and durations).
- Xmas tree valve positions at handover (open / closed, including choke position).
- Isolations from adjacent wells, manifolds, production facilities.
- Last reported Closed-In Tubing Head Pressure (CITHP) and estimated static bottom hole temperature.
- Tubing and annulus fluid types and gradients.
- Mechanical status (corrosion, scale) of completion tubulars, seals, and casing strings.
- Changes in reservoir properties (i.e. pressure decrease or increase from original, H_2S, CO_2, hydrates, wax). Note that H_2S is to be quoted as partial pressure.

2.2 PLANNING

Well interventions and workovers can, by their nature, have several uncertainties with regard to pressure integrity of tubing / casing strings and / or valve integrity. It is important to highlight these uncertainties at the planning stage of the well and build in contingencies so the minimum standard of two independent tested barriers is maintained.

A pre-completions meeting must be held on the rig prior to completions operations to communicate the programme, known hazards and contingencies to the OIM and the relevant department heads. The OIM is to ensure all non-standard chemicals are identified and that correct procedures are in place to handle any spills or human contacts as described on the Material Safety Data Sheets (MSDS).

2.3 KILLING THE WELL

With a completion installed, there are three methods of killing the well:

1. Bullheading the tubing contents back into the formation by displacing with a heavier fluid.
2. Setting a deep-set plug and conventionally circulating a heavy fluid down the tubing with returns from the annulus.
3. Setting a deep-set plug and reverse circulating a heavy fluid down the annulus with returns from the tubing.

Both 2 and 3 prevent possible damage to the reservoir formation from foreign fluids but rely on being able to set a plug in the tubing or liner.

There is no single preferred method, as this depends on operational conditions for a given well.

2.4 REMOVING THE XMAS TREE

Before removing the Xmas tree, there must be a minimum of two independent tested barriers in place. As these barriers cannot always be tested in the direction of flow, a test from above on a cement plug or on a mechanical barrier, such as a packer or plug (with either a Chevron or V-ring double seal stack), will be considered suitable.

2.5 COILED TUBING

If the intervention or workover has the possibility to use coiled tubing, there must be two independent means of cutting that particular size of tubing and then sealing on the open wellbore. This ability to cut and seal should have been proved either prior to shipping the equipment to the rig or as part of the initial rig up. If the tubing contains electric line cable, the coiled tubing rams must also have been shown capable of cutting and sealing for that configuration.

2.6 HYDRATES

Hydrates occur when light hydrocarbons are mixed with free water molecules at the correct pressure and temperature conditions. Under specific temperature and pressure conditions, hydrates can form spontaneously.

When conducting intervention or workover operations, as a minimum, the rig should hold one IBC (14.3 US gallons) of methanol and two IBCs (2 x 14.3 US gallons) of mono-ethylene glycol (MEG) or similar.

As a rule of thumb, with natural gas as the light hydrocarbon, a 50/50 mix of glycol and seawater has a freezing point of minus 44 degrees C. The best mix of glycol to water is 60% glycol to 40% water and this gives a freezing point of minus 60 degrees C.

The possibility of hydrates forming across Xmas tree valves should be addressed as this could greatly reduce the rig's chances of securing a well. This is of particular note when running long wireline toolstrings and/or coiled tubing through the well.

Ensure all intervention and workover programmes have addressed the issues relating to hydrate formation for your given conditions.

2.7 HYDROGEN SULFIDE (H_2S)

A hydrogen sulfide environment is defined in MR0175-2000 as one in which the partial pressure of H_2S in a crude oil system is equal to or exceeds 0.05 psi or total sour gas system pressures exceed 65 psi.

For ease of measurement, the following H_2S concentrations in air will be used as detection triggers:

0 – 5 ppm	Detectors set to low level alarm at 5 ppm. Monitor area.
5 – 10 ppm	Detectors set to high level alarm at 10 ppm. Establish barriers around H_2S area.
> 20 ppm	Self-contained breathing apparatus or a connection to the cascade system must be worn in H_2S concentrations in air 20 ppm or above.

(Reference HSE Manual, HQS-HSE-PP-01, Section 4, Subsection 3.1, Hydrogen Sulfide and Medical Protocols, HQS-HSE-PR-03, Section 6, Subsection 7, Hydrogen Sulfide).

2.8 EMERGENCY SHUTDOWN SYSTEMS (ESD)

In the event of any given emergency or equipment failure, any rig-based temporary hydrocarbon process facility must be fitted with means of automatically and manually shutting down flow through that facility.

The OIM is responsible for ensuring that the relevant heads of departments (including Drillers and ADs) are aware of the locations of the ESD buttons, the sequence logic of the shutdown system and to ensure that the ESD has been fully tested prior to the flow of any hydrocarbons.

When using a Xmas tree riser and intervention system, the OIM must also ensure that the relevant heads of departments (including Drillers and ADs) are aware of the sequence logic of the ESD systems which control the following:

- Shutdown of the process facilities.
- The closure of the hydraulic actuated Xmas tree valves.
- The release of the production riser disconnect package. This ESD system must be witnessed to operate as per the design sequence logic and the time taken to perform all functions recorded and logged.

For stand-alone systems such as hydraulic pumps connected directly to flowheads or Xmas tree wing / master valves, a clearly defined process must exist detailing who is responsible for closing these valves in an emergency. When the wellbore is open, these pumps must be constantly manned with direct communication to the rig floor to enable swift closure.

3 OTHER INTERVENTION / WORKOVER CONSIDERATIONS

3.1 TRAPPED GAS

Possible areas where gas can become trapped when conducting completions or workovers are:

- Below a plug set in the production hanger.
- Below a deep-set plug set in the completion tailpipe or packer assembly.
- Directly below the packer element in the annulus between the casing / liner and the completion string. This has the possibility of rapidly expanding (depending on annulus fluid density) up the hole when the packer is released or milled. A 1 bbl gas bubble at 1000 psi pressure will expand to 68 bbls at surface (14.7 psi).

3.2 HYDROCARBON RELEASE DURING WIRELINE OPERATIONS

Wireline can be run into the wellbore as slickline or braided line with or without the capability to supply electrical current.

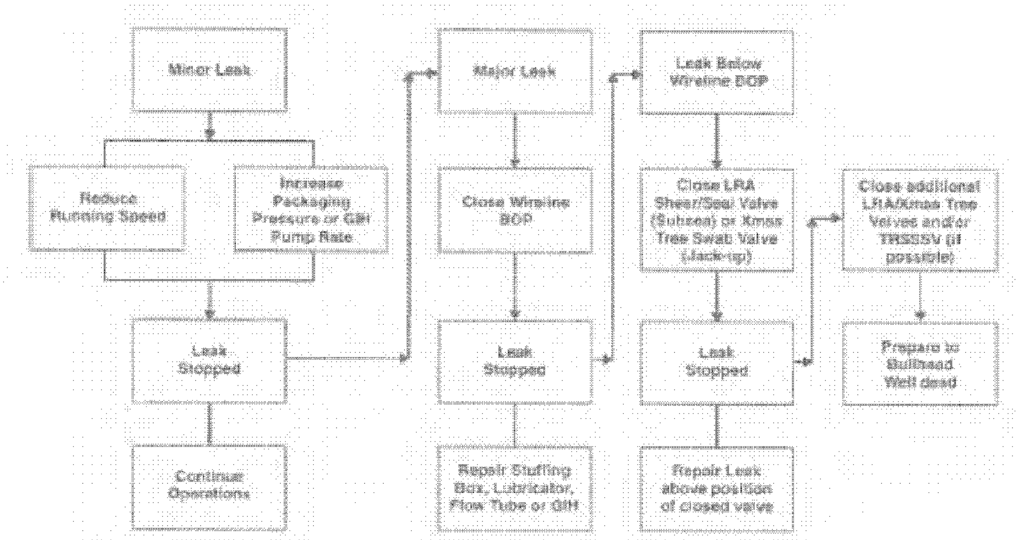
When pressure control equipment is installed, the stuffing box provides a seal around the slickline as it passes in / out of the lubricator. The stuffing box packings are adjusted by a nut and should be energized enough to form a seal around the slickline but not so much as to prevent the tools from entering the well.

When using braided wire, the stuffing box is replaced by a grease injection head, which allows grease to be injected at high pressure to form a seal around the braided wire. The integrity of the grease injection head is affected by:

- Number of flow tubes
- Cable clearance within the flow tubes
- Type and pressure of grease injected
- Temperature
- Tubing head pressure
- Well gas oil ratio (GOR)
- Cable speed

The following flowchart indicates action to be taken in the event of a hydrocarbon release during a completion or workover intervention.

Figure 8.9.1 – Hydrocarbon Release during Completion or Workover



GIH	= Grease Injection Head
LRA	= Lower Riser Assembly (Subsea)
TRSSSV	= Tubing Retrievable Subsea Safety Valve

NOTE: A minimum of two independent tested barriers must be maintained prior to repairing any surface components of the wireline pressure control equipment.

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1 GENERAL

An important aspect of well control is the proper selection, maintenance and utilization of the blowout preventers, chokes and choke manifolds, mud-gas separators, degassers, mud-monitoring equipment and all other well control related equipment.

Only with correctly selected equipment, which has been properly maintained and serviced, can successful well control procedures be conducted.

2 MINIMUM BOP REQUIREMENTS

The BOP stack contributes to only a part of the integrity of a well, and the wellhead equipment, casing and the competence of the open hole must also be considered for the purposes of pressure containment.

Casing, wellheads and pressure control equipment must, as a minimum, meet the working pressure requirements determined by well conditions and activity.

Well control equipment can be considered available in five (5) working pressure categories:

- 2,000 psi/13,800 kPa/138 bar (2M)
- 3,000 psi/20,700 kPa/207 bar (3M)
- 5,000 psi/34,500 kPa/345 bar (5M)
- 10,000 psi/69,000 kPa/609 bar (10M)
- 15,000 psi/103,500 kPa/1035 bar (15M)

Although not very common, 20M equipment also exists.

Over the years, equipment has been designed to conform to various standards. Each Installation must comply with the specification of well control equipment (RP53, API 16A, API 16C, etc.) and the revision level as was used in the original design and commissioning. If the equipment has been subsequently upgraded to another standard, then the new standard will apply. Notwithstanding the above, the following are the minimum acceptable requirements for all Company Installations.

The following well control equipment and procedures are regarded as a minimum requirement:

- The pipe rams, shear ram, spool pieces, gate valves and any component attached to the BOP stack must have a working pressure rating that exceeds the maximum anticipated surface pressure under 'worst case' operating conditions.
- The working temperature rating of the BOP stack is dependent upon the maximum anticipated continuous temperature to which it is likely to be exposed (e.g. ram rubbers).
- The annular preventer must have a working pressure rating of at least 50% of the working pressure rating of the ram type preventers.
- The elastomeric and metallic components of the BOP stack must be compatible with the anticipated well fluids.
- The BOP stack, while drilling or during open hole, must have two means of closing on all tubulars and open hole. The annular is the typical second means of closing on open hole.

2.1 GENERAL

When the BOP is installed on the wellhead, unless an emergency condition materializes which requires immediate action, a Permit-to-Work is required for function testing or trouble shooting operations on the BOP. The OIM or his designee must be present and must concur with planned functions.

Wellhead and LMRP connector functions must be secured against inadvertent and unintentional disconnect from all control panels and reels. The procedure to actuate the function shall consist of a sequence of unique actions that expose the latch / unlatch controls. The sequence must be different than the sequence for other BOP functions. Discrete panels must include a transparent cover which is fastened by means of a release mechanism; hydraulic hose reels shall have locked covers installed over the operating handle; and touch screens must have a clear warning screen that appears and requires confirmation before allowing the disconnect operation to occur.

Blind/shear ram functions from all control panels must be protected by a transparent cover to prevent inadvertent operations. Touch screen panels must have a clear warning screen that appears and requires confirmation before allowing the operation to occur.

2.1.1 MILLING OR SIDE-TRACKING OPERATIONS

Prior to the cutting of a window in casing for kick off purposes, or for extensive milling operations, the client must be advised that time needs to be provided to open and clean the BOP as soon as possible after the BOP is available for service.

To minimize damage, a series of considerations shall be discussed with the client and actions taken that include:

- Use of ditch magnets in mud return system
- Jet sub for BOP cleaning
- Once milling has begun the BOPs shall only be operated or used in an emergency
- Pumping regular hi-vis pills through the BOP to help lift cuttings
- Only pumping down choke and kill lines
- Hold slight back pressure on choke and kill wing or failsafe valves prior to opening
- Clean out of sand traps and flowline
- Once milling is complete the BOP stack shall not be operated until properly flushed and cleaned out.

As soon as practicable after the milling operation is complete the BOP stack shall be opened, thoroughly cleaned and inspected.
Ensure that the proper well barriers are in place prior to opening up the BOP for inspection.

When cleaning out the BOP, special attention must be paid to the annular pistons/cylinders and the rear of the ram blocks adjacent to the piston rods, where the scoring of these areas will result in an operating failure subsea.

Sub-sea choke and kill valves must be kept closed during the cutting or milling operation, and flushed with hi-vis mud after the hole has been circulated clean of metal shavings (swarf).

In order to avoid damage to the BOP stack, milling operations shall not take place inside and adjacent to the bore of the BOP stack without the approval of the Business unit Director of Operations Performance and a written plan. Any proposed mill for the operation must avoid having cutters along its OD that may bite into the BOP. The bottom of the mill shall be determined relative to its position in the BOP stack.

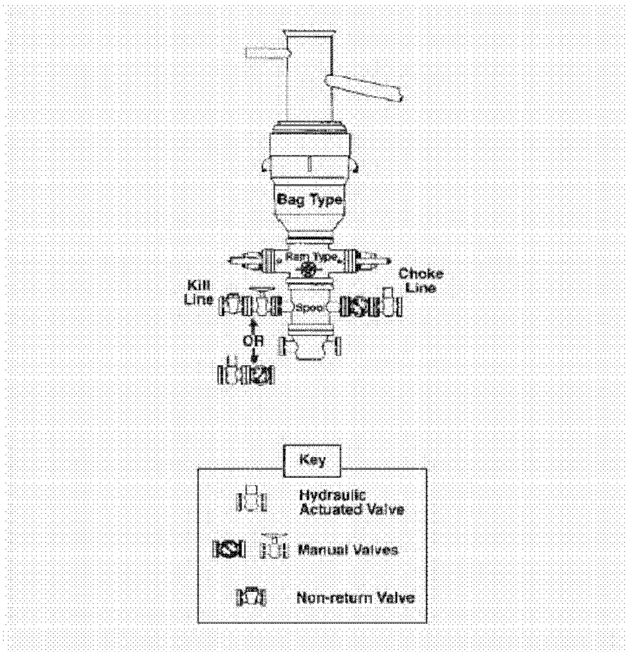
2.2 SURFACE BOP'S

The minimum requirements for the following systems are as follows:

2.2.1 2M STACKS

One (1) annular type preventer and one (1) ram type preventer.

Figure 9.1.1, 2M Stack



2.2.2 3M AND 5M STACKS

One (1) annular type preventer and two (2) ram type preventers.

Figure 9.1.2 3M/5M Stack

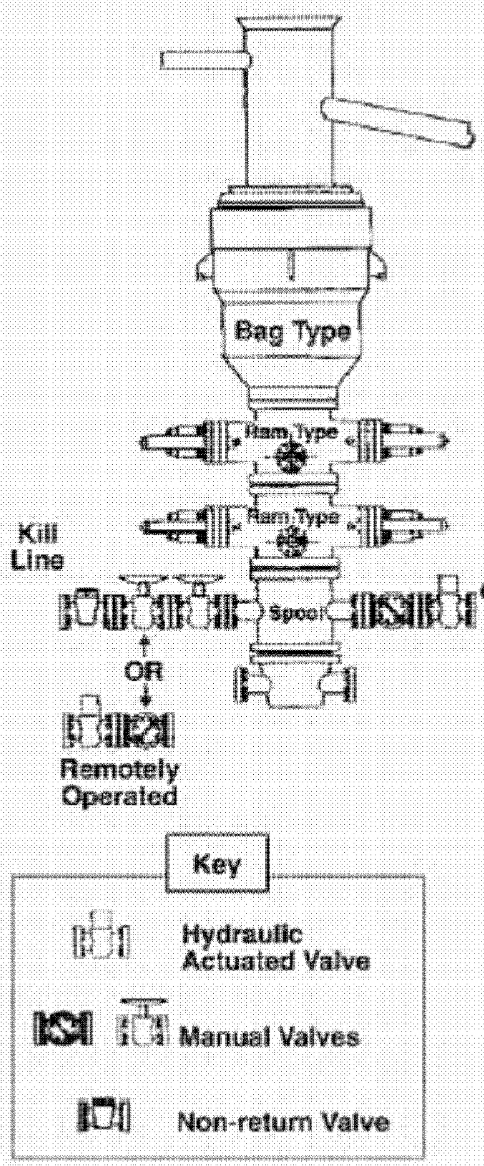
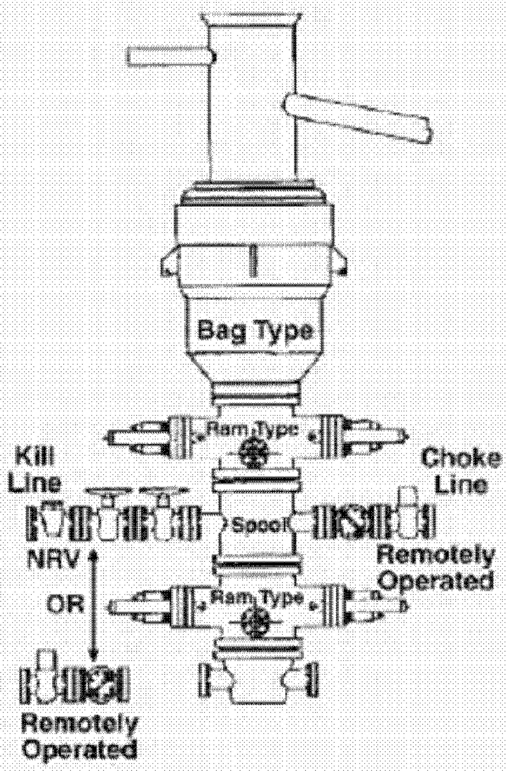


Figure 9.1.3 3M/5M Stack

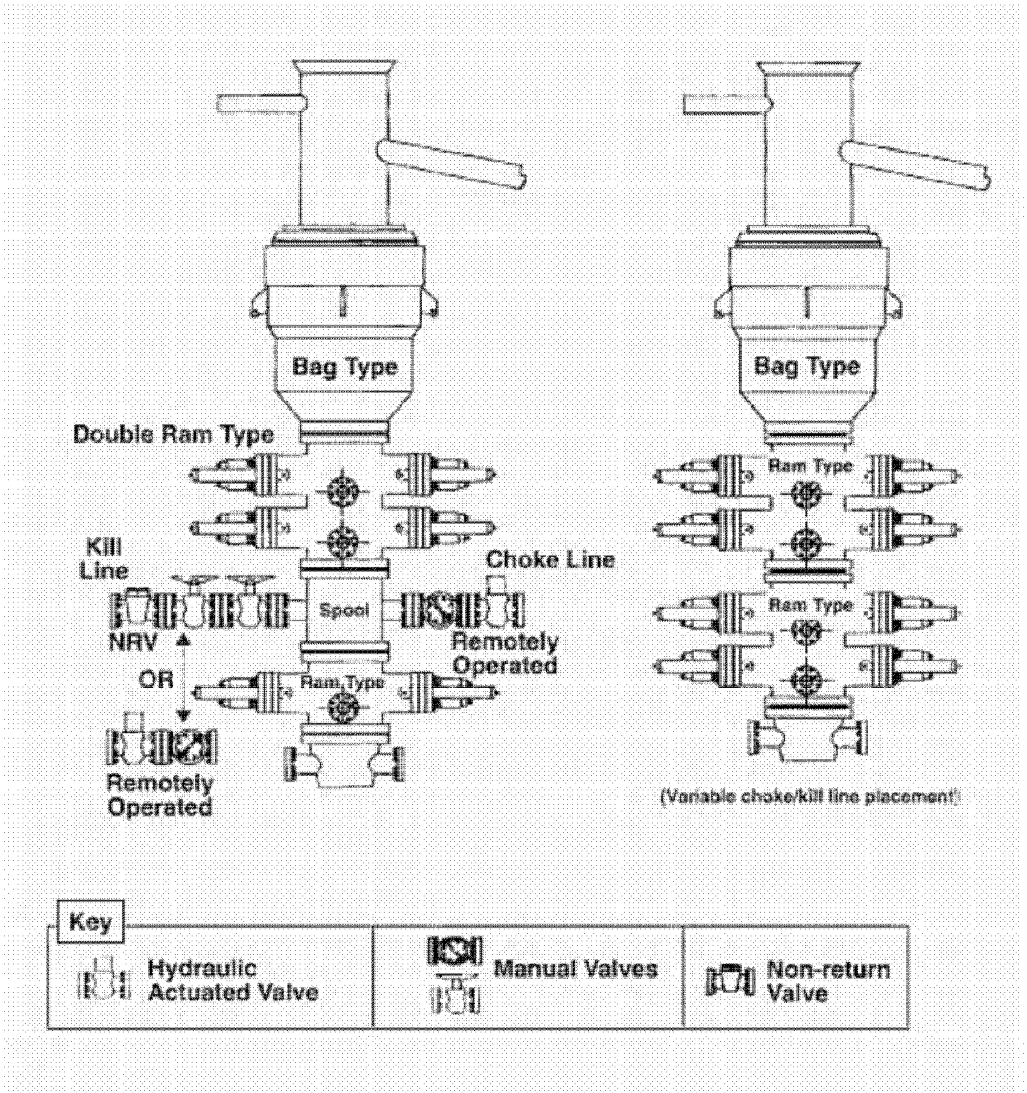


2.2.3 10M AND 15M STACKS

One (1) 5M (10M stack) or 10M (15M stack) annular type preventer and three (3) 10M or 15M ram type preventers (of which one [1] will be a blind/shear ram), respectively.

Figure 9.1.4 10M/15M Stack With Spool

Figure 9.1.5 10M/15M Stack without Spool



2.2.4 CHOKE AND KILL OUTLETS

- There must be at least one (1) kill and one (1) choke outlet with at least two (2) full opening valves on each choke outlet.
- On 5M, 10M, and 15M stacks at least one valve must be a remote hydraulically operated valve.
- For 5M, 10M and 15M stacks there must be at least two (2) full opening valves plus a check valve, or two (2) full opening valves (one of which is remotely operated) on each kill inlet.
- For 2M and 3M stacks there must be at least one (1) full opening valve plus a check valve, or two (2) full opening valves (one of which is remotely operated) on each kill inlet.

2.2.5 BLIND/SHEAR RAMS

- There must be at least one (1) set of blind/shear type rams.
- The blind/shear rams must be capable of shearing the highest grade and heaviest drillpipe used on the rig (HWDP excluded) and sealing of the well in one operation.

2.2.6 RAM LOCKS

- All ram type preventers must be equipped with ram locks.

2.2.7 ANNULARS

- Annular elements must be compatible with well-bore fluids.

2.3 SUBSEA BOPs

2.3.1 GENERAL

Subsea BOP stacks must be landed and/or disconnected with the slip joint locked closed using an appropriate riser landing joint.

Subsea BOP control hose and MUX cable reels must be mechanically secured against accidental operation while the BOP is latched on the wellhead. Furthermore, the power to the drive motors for the reels must be isolated when the BOP stack is secured to the wellhead.

Extreme care should be taken to avoid creating a situation where the hydraulic latch pressure to the LMRP connector may be reduced and allow it to disconnect. In order to minimize the risk of dropping the BOP stack while it is being run, care should be taken to avoid actuating unnecessary BOP functions such as those associated with troubleshooting the BOP. Changing pods while running the BOP should be avoided.

When running and pulling the BOP, the subsea accumulators must be in the charge position and positive pressure must be provided to the latch port on the LMRP connector. The BOP should normally be run in the drilling mode.

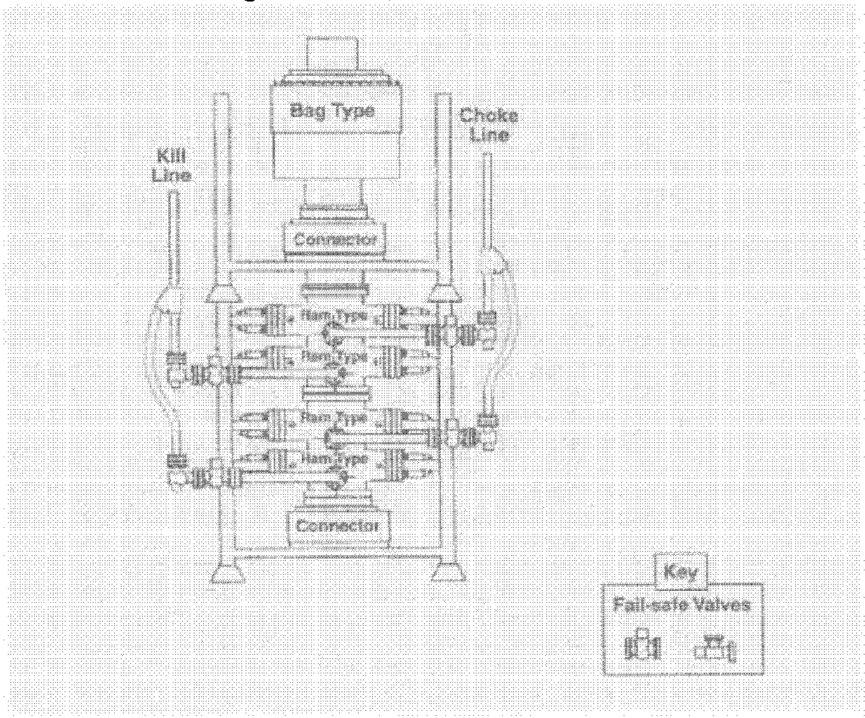
The correct gallon count each time subsea rams are opened must be confirmed. This is critical to ensure BOP rams are fully open before tripping large bore tools.

The minimum requirements for the following systems are as follows:

2.3.2 10M AND 15M STACKS

One (1) 5M (10M stack) or 10M (15M stack) annular type preventer and four (4) 10M or 15M psi ram type preventers (of which one [1] will be a blind/shear ram).

Figure 9.1.6, 10M / 15M Stacks



2.3.3 CHOKE AND KILL OUTLETS

- There must be at least one (1) kill and two (2) choke outlets on 10M and 15M stacks.
- This configuration will allow circulation beneath the blind/shear rams.

2.3.4 BLIND/SHEAR RAMS

- There must be at least one (1) set of blind/shear type rams.
- The blind/shear rams must be capable of shearing the highest grade and heaviest drillpipe on the rig (HWDP excluded) and sealing of the well in one operation.

2.3.5 RAM LOCKING DEVICES

- All sealing ram type preventers must be equipped with ram locks.

2.4 PIPE RAMS

The BOP stack must have at least the following:

- Three (3) pipe ram preventers with mechanical locking devices.
- If 1 set of pipe rams has been dressed with casing rams then, as a minimum, the remaining 2 sets of pipe rams must be capable of closing around the drillpipe across the BOP stack while drilling operations are being conducted.
- The designated hang-off rams (fixed or variable) must be capable of supporting the maximum anticipated string weight with the drillpipe in use for the well.

2.5 ANNULARS

- There must be at least one (1) annular preventer in the LMRP.
- Annular preventer elements must be compatible with well-bore fluids.

2.6 SUBSEA ACTUATED GATE VALVES

- Each outlet must be equipped with two (2) subsea actuated gate valves.
- Subsea actuated choke and kill gate valves may be controlled by either of the methods below:
- The open and close valve functions consist of individual open and close hydraulic controls (plus a block position) from each subsea pod. Valves will have a spring that closes the valve in the event hydraulic closing supply is unavailable and the open hydraulic supply is vented.
- The open operating chamber on the valve has individual control from each subsea pod. The close hydraulics consist of a regulated hydraulic supply which provides continuous closing pressure; this closing pressure is sufficient to close the valve when the open pressure is vented. Valves will have a spring that closes the valve in the event hydraulic closing supply is unavailable.

2.7 WELLHEAD AND LMRP CONNECTORS

- An integral part of the subsea BOP stacks are the Wellhead and Lower Marine Riser Package (LMRP) Connectors.
- The wellhead connector must have a pressure rating equal to or greater than that of the BOP stack.

- In areas or operations where hydrate formation is a possibility (see Section 8.4.4), wellhead connectors must be fitted with flush ports and hydrate seals.
- The LMRP Connector must have a pressure rating equal to or greater than that of the annular preventer in the LMRP.
- Both the Wellhead and LMRP Connectors must be run with ring type gaskets designed to provide a metal-to-metal seal. A Hy-Car type ring gasket will be used only when a metal-to-metal seal cannot be achieved but is not considered a permanent alternative to the metal-to-metal seal.
- BOP equipment must not be run on wellheads where the well head angle is greater than 1.0 degree to avoid key-seating damage unless (1) approval is obtained from the SVP of the Business unit or his designee and (2) the client accepts responsibility, in writing, for any and all damage that might occur (including repair and / or replacement of the damaged equipment and full compensation during any resulting idle period). (ref: Field Operations Manual HQS-OPS-HB-05, Riser Operations Procedure)

Care should be taken to monitor casing wear whenever the well profile has a shallow kickoff or doglegs just below the mudline.

2.8 MARINE RISER

Connects the diverter and BOP stack in subsea systems, with an inside diameter greater than that of the BOP stack.

Choke and kill lines on the riser have a working pressure that is equal to or greater than the ram preventers in the stack.

If the riser is equipped with a mud booster line, it should be fitted with a test valve mounted on or near the LMRP.

In deep water, a riser fill-up valve should be run if the collapse pressure of the riser could be exceeded.

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1 GENERAL

Each Installation must comply with the specification of well control equipment (RP 64, API 16D, etc.) and the revision level as was used in the original design and commissioning. If the equipment has been subsequently upgraded to a new standard, then the new standard will apply. Notwithstanding the above, the following are the minimum acceptable requirements for all Company Installations.

Closing time must not exceed 30 seconds for diverters smaller than 18-3/4" (476 mm) nominal bore and 45 seconds for diverters of 18-3/4" (476 mm) nominal bore and larger.

The design of any new diverter or upgrades to the system must utilize the design procedure outlined in API RP-64, API RP-53, API RP-16D, ISO TC 67 / SC 4 N, and MMS. New systems should comply with the latest specification, whereas upgrades/modifications/re-works should meet the requirements in effect when the unit was built.

2 SWAMP BARGES AND JACK-UP RIGS

The diverter packer(s) must be capable of closing and sealing around the kelly, drillpipe or casing.

The diverter system must have a minimum working pressure rating of 500 psi (3,450 kPa/34.5 bar).

2.1 OVERBOARD LINES

At least one (1) 12" (305 mm) overboard line must be installed to permit venting of the wellbore returns away from the rig and personnel.

The overboard line(s) may extend from a common line that connects to the diverter housing. The common line must be at least 12" (305 mm) nominal diameter/schedule 80 as will the nominal diameter of the overboard line(s).

The overboard line(s) must be installed with a minimum number of bends and all lines well secured.

Special care must be taken to protect pipe bends from erosion by:

- The use of long radius pipe bends.
- Fluid targeted "T".
- Providing extra metal thickness at bends.

2.2 DIVERTER SYSTEM

Each diverter line must be equipped with a remotely operated, full opening, unrestricted valve.

The diverter system must be equipped so that (at least one of) the diverter overboard line(s) automatically opens to vent when the diverter packing closes. If there are 2 lines, a means of switching flow from 1 line to the other without closing in the system must be provided.

If the flowline and the diverter overboard outlet from the well share a common line or if the flowline is connected to the diverter housing, a remotely operated valve must be installed to automatically shut off mud returns to the pits when the diverter is closed.

All lines in the system are to be fitted with welded or flanged connections. Sleeve-type connections must not be used.

3 FLOATING RIGS

A diverter that is capable of closing and sealing around either the kelly or drillpipe must be installed and locked into the diverter housing to prevent the slip joint from extending upwards through the rotary table should pressure be encountered.

The diverter system must have a minimum working pressure rating of 500 psi (3,450 kPa / 34.5 bar).

A fill-up line to the diverter housing must have a non-return valve installed in the line near the diverter housing that is rated to the same pressure as the diverter system, i.e. minimum 500 psi (3,450 kPa / 34.5 bar).

3.1 OVERBOARD LINES

At least one (1) overboard line of 12" (305 mm) nominal diameter must be installed to permit venting of the wellbore returns safely away from the rig and personnel.

The overboard lines may extend from a common line that connects to the well beneath the diverter head. The common line should be at least 12" (305 mm) nominal diameter/schedule 80.

The overboard lines must be installed with the minimum number of bends and must be securely anchored.

Special care must be taken to protect pipe bends from erosion by:

- The use of long radius pipe bends.
- Fluid targeted "T".
- Providing extra metal thickness at the bends.

3.2 DIVERTER SYSTEM

Only full opening, unrestricted valves must be used in the diverter relief system and these must be remotely operated.

The diverter system must be equipped so that at least one diverter overboard line automatically opens to vent when the diverter packer is closed. A means of switching flow from one overboard line to the other without closing in the system must be provided.

If the flowline and the diverter relief outlet from the well share a common line or, if the flowline is connected to the diverter housing, a remotely-operated valve must be installed to automatically shut off mud returns to the pits when the diverter is closed.

Sleeve-type connections must not be used in the diverter system.

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1 GENERAL

Over the years, equipment has been designed to conform to various standards. Each Installation must comply with the specification of well control equipment (RP 53, API 16D, API 16E, etc.) and the revision level as was used in the original design and commissioning. If the equipment has been subsequently upgraded to another standard, then the new standard will apply. Notwithstanding the above, the following are the minimum acceptable requirements for all Company Installations.

2 SURFACE BOP SYSTEMS

The surface closing unit must consist of an independent automatic accumulator unit rated for at least 3,000 psi (20,700 kPa, 207 bar) working pressure with a control manifold clearly showing 'open' and 'close' positions for each preventer and the pressure operated choke line valve(s).

Surface BOP operating units must be equipped with 0-3,000 psi (0-20,700 kPa, 0-207 bar) or 0-5,000 psi (0-34,500 kPa, 0-345 bar) (as appropriate for the accumulator working pressure) regulator valves, complete with a manual override, which must not fail open causing a total loss of operating pressure. This unit must be located in a safe area, which is defined as a position where the unit can be operated with the well on fire, or out of control.

If operating pressures are set high for closure, it must be readjusted to the manufacturer's recommended pressure after closure and/or prior to running casing, routine pressure testing and stripping operations.

The surface closing unit must be capable of operation using a minimum of two independent power sources e.g. electricity, compressed air, compressed nitrogen.

The surface closing unit manifold must be equipped with a full opening valve and fittings to enable attachment of an external charge pump.

A facility must exist to by-pass the ram preventer pressure regulator in order to enable full accumulator pressure to be applied to the ram operating piston.

2.1 ACCUMULATOR CAPACITY/RESPONSE TIME

The accumulator volume of the surface BOP system must be sized to keep a remaining stored accumulator pressure of 200 psi (1380 kPa, 13.8 bar) or more above the minimum recommended pre-charge pressure after conducting the following operations (with the pumps inoperative):

- Close all ram and annular functions at zero wellbore pressure.

The surface BOP control system must be capable of closing each ram preventer within 30 seconds.

On surface BOP systems, closing time must not exceed 30 seconds for annular preventers smaller than 18-3/4" (476 mm) nominal bore and 45 seconds for annular preventers of 18-3/4" (476 mm) nominal bore and larger.

Response time for remotely operated choke and kill valves (either open or close) must not exceed the minimum observed ram closing time.

2.2 ACCUMULATOR PRE-CHARGE

The surface accumulators fitted with bladders, pistons, or floats must have a pre-charge equal to 1/3rd of the rated pressure, i.e.: 1000 psi (6900 kPa, 69 bar) for 3000 psi (20,700 kPa, 207 bar) systems and 1500 psi (10,345 kPa, 103 bar) for 4500/5000 psi (31,000 kPa, 310 bar/34,500 kPa, 345 bar) systems.

The pre-charge pressure must not exceed 100% of the accumulator rated working pressure.

Only Nitrogen (N_2) gas must be used for accumulator pre-charge.

2.3 FOUR-WAY VALVES

All four-way valves must be in either the 'open' or 'close' position during normal operations and should not normally be left in the neutral position.

2.4 REMOTE PANELS

On surface BOP installations, there must be two (2) remote control panels, each one clearly showing 'open' and 'close' positions for each preventer and the remotely operated choke line valve(s). Each of these panels must include a master control valve and controls for the regulator valves and for a by-pass valve.

One panel must be located near the Driller's station, the other panel is to be located in a safe area. If the accumulator closing unit is in a safe area, it may be considered as the other panel.

2.5 ACCUMULATOR CHARGING PUMPS

The surface BOP unit must include a minimum of one (1) electric pump and two (2) backup air pumps for accumulator charging.

With the accumulator system removed from service, the pumps must be capable of:

- Closing the annular preventer on the minimum size drillpipe being used.
- Opening the remotely operated choke line valve.
- Maintaining a minimum of 200 psi (1380 kPa, 13.8 bar) pressure above Accumulator pre-charge pressure on the closing unit manifold.
- Functions to be completed within two (2) minutes or less.

The combined output of all pumps must be capable of charging the entire accumulator system from pre-charge pressure to the maximum rated control system working pressure within 15 minutes.

3 SUBSEA BOP SYSTEMS

The subsea BOP system closing unit must consist of an independent automatic accumulator unit rated for at least 3,000 psi (20,700 kPa, 207 bar) working pressure with a control manifold on the hydraulic pump unit, clearly showing 'open' and 'close' positions for each preventer and the choke and kill valves. These valves must not be left in the 'neutral' (Block) position (not applicable to multiplex BOP control systems).

Subsea BOP stack operating units must be equipped with 0-3,000 psi (0-20,700 kPa, 0-207 bar) or 0-5,000 psi (0-34,500 kPa, 0-345 bar) (as appropriate for the accumulator working pressure) regulator valves, complete with a manual override, which must not fail open causing a total loss of operating pressure. This unit must be located in a safe area (not applicable to multiplex BOP control systems).

The hydraulic pressure for the initial closure of the annular preventer must be set at the maximum manufacturer's recommended pressure for the drillstring in the hole during normal operations. However, it must be adjusted to the manufacturer's recommended pressure for the pipe across the BOP after closure and/or prior to running casing, routine pressure testing and stripping operations.

Operations Manager Performance have the option to modify this recommended closing pressure, especially when floating rigs are operating in conditions of significant heave.

The closing unit for subsea systems must be capable of operation using a minimum of two independent power sources e.g. electricity, compressed air, compressed nitrogen.

The closing unit manifold for subsea systems must be equipped with a full opening valve and fittings to enable attachment of an external charge pump.

3.1 ACCUMULATOR CAPACITY/RESPONSE TIME

As a minimum, the useable BOP accumulator system volume, both surface and stack-mounted bottles, must be sized to retain stored accumulator pressure of 200 psi (1380 kPa, 13.8 bar) or more above the minimum recommended pre-charge pressure, after conducting the following operations at zero wellbore pressure (with the pumps inoperative):

- Close all rams (maximum of four [4]), lock all ram locking devices, and close one annular.
- Unlock all ram locking devices, open all rams (maximum of four [4]) and open one annular.
- Retain 50% of the required volume in reserve.

The subsea BOP control system must be capable of closing each ram preventer within 45 seconds or less.

Closing time must not exceed 60 seconds for the annular preventer.

Response time for choke and kill 'fail-safe' valves (either open or close) must not exceed the minimum observed ram closing time.

The riser connector must unlatch in 45 seconds or less. (This should not be interpreted to mean that the entire Emergency Disconnect Sequence completes within 45 seconds.)

3.2 DYNAMICALLY POSITIONED FLOATING RIGS

On dynamic positioned rigs the stack-mounted accumulators can be used to supplement the hydraulic fluid for all functions selected for emergency disconnect sequence.

The EDS shall be designed to ensure the well is shut in as part of the functional sequence. The functions typically selected for emergency disconnect sequence (EDS) that take:

- Close pipe rams and hang off (This maybe accomplish in a preliminary disconnect sequence)
- Arm auto-shear
- Close all choke and kill valves*
- Close shear blind rams
- Engage shear ram locking device
- Block all pressured control functions in BOP
- Retract / unlock all pod stingers
- Retract / unlock all choke and kill stabs / connectors
- Unlock primary and secondary riser connector

The EDS as a minimum shall include release of the LMRP connector and closure of at least one blind/shear ram.

In the event that subsea BOP functions are inoperative due to a failure of the main control system an emergency back-up system(s) should be included on the BOP, emergency back-up systems (ROV intervention, deadman or acoustics)

The functions that are typically selected for back-up control ROV system emergency operation include:

- Close hang-off pipe ram
- Engage the hang-off pipe ram locking devices
- Shear the drillpipe with the shear ram
- Engage the shear ram locking devices (if equipped)
- Shut in well with blind/shear ram
- Engage the blind-shear ram locking devices
- Retract/unlock choke and kill stabs / connectors
- Retract all hydraulic and acoustic stabs
- Unlock primary and secondary riser connector
- Unlock primary and secondary wellhead connector
- Retract pod stingers
- Operate riser and wellhead connector gasket retaining systems

The autoshear and deadman are back-up systems that can be armed or disarmed. In the arm mode they secures the well in the event of separation of LMRP from BOP or in some cases the event of loss of both hydraulic supplies and loss of power signal to both MUX control pods by closing the blind/shear rams.
The acoustic system is a backup system that can be armed or disarmed and operated with an acoustic signal to control functions on the acoustic pod.

The BOP or Lower Stack mounted and isolated accumulators should only be sized to supply fluid volume and pressure for those functions that are required for the particular backup system after a disconnect has occurred, Dead-man, Auto-Shear, Acoustics, etc. Sizing requirements should meet the requirements of API.

These bottles can however be used to supply high pressure shear and related features during a connected. Accumulator bottles for auto-shear, deadman, and acoustics systems may be shared.

3.3 MOORED FLOATING RIGS

On moored rigs the stack-mounted accumulators should provide the hydraulic fluid for closing the largest annular BOP plus 50% reserve.

The stack-mounted accumulators also help minimize the response time to close the annular.

3.4 ACCUMULATOR PRE-CHARGE

For subsea systems, piston type or bladder type accumulators must have a pre-charge equal to 1/3rd of the rated pressure, i.e.: 1000 psi (6,900 kPa, 69 bar) for 3000 psi (20,700 kPa, 207 bar) systems and 1500 psi (10,345 kPa, 103.5 bar) for 4500/5000 psi (31,000 kPa, 310 bar/34,500 kPa, 345 bar) systems plus hydrostatic and temperature compensation. Designated shear ram bottles may be precharged higher to maximize the minimum amount of pressure to shear drillpipe.

A gradient of 0.445 psi/ ft (10 kPa/m, 0.1 bar/m) is used to calculate the hydrostatic compensation; additional factors for temperature change are included for systems operating deeper than 3,000′ water depths.

Nitrogen (N_2) gas must be used for accumulator pre-charge.

Float type accumulators shall not be used subsea for 5000 psi control systems, and are limited to 3000′ water depths for 3000 psi control systems.

3.5 FOUR-WAY VALVES

All four-way valves on the accumulator manifold for subsea systems on the hydraulic pump unit or diverter panel must be in either the 'open' or 'close' position during normal operations. They must not normally be left in the 'block' position.

3.6 REDUNDANCY

For subsea systems, there must be complete redundancy of hydraulic supply and control for all subsea BOP stack functions.

3.7 REMOTE CONTROL PANELS

For subsea systems, there must be two (2) remote control panels, each one clearly showing 'open', 'close' and 'block' ('vent') positions for each preventer and the choke and kill valves. During operations, valves are not to be left in the block position.

One panel must be located near the Driller's position; the other panel is to be located in a safe area.

3.8 ACCUMULATOR CHARGING PUMPS

The subsea hydraulic pumping unit (HPU) must include at least two pump systems, each having independent dedicated power sources.

With the surface and subsea accumulator system removed from service, the pump system must be capable of:

- Closing the annular preventer on the minimum size drillpipe being used.
- Opening the two (2) choke line valves.
- Maintaining a minimum pressure of (a) the operating pressure level recommended by the annular preventer manufacturer to effect a seal on the annulus or (b) the operating pressure of the subsea actuated choke valves, whichever is greater.
- Functions to be completed within two (2) minutes.

The combined output of all pumps must be capable of charging the entire accumulator system (both surface and subsea bottles) from pre-charge pressure to the maximum rated control system working pressure within 15 minutes. (This requirement does not include accumulators for emergency systems.)

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1 GENERAL

Each Installation must comply with the specification of well control equipment (RP 53, API 16A, API 16C, API 16D, etc.) and the revision level as was used in the original design and commissioning. If the equipment has been subsequently upgraded to another standard, then the new standard will apply. Notwithstanding the above, the following are the minimum acceptable requirements for all Company Installations.

2 CHOKE MANIFOLDS

For all installations, the working pressure of the choke manifold must equal or exceed the working pressure of the ram preventers.

In the case of 2M stacks, the working pressure of the choke manifold must be at least equal to the working pressure of the annular.

2.1 SWAMP BARGES AND JACK-UP RIGS

2.1.1 FLOW PATHS

At least three flow paths must be provided that are capable of flowing well returns through conduits that are 2" (51 mm) nominal diameter or larger.

At least one flow path must be equipped with a remotely controlled pressure operated adjustable choke. Simplified choke manifolds without remote control choke may be acceptable on light rigs with 2M or 3M stacks.

At least one flow path must be equipped with a manually operated adjustable choke.

One flow path should permit returns to flow directly to the pit, discharge manifold or other downstream piping without passing through a choke. Two gate valves with full rated working pressure must be provided in this unchoked flow path.

2.1.2 COMPONENT SPECIFICS

The chokes, the two (2) valves controlling the unchoked discharge flow path and all equipment upstream of these items must have full rated working pressure and must be equipped with flanged, studded or clamp hub connections.

Two gate valves must be provided upstream of the choke in each choke flow path.

At least one gate valve must be installed downstream of each choke ahead of any discharge manifold. This valve may or may not carry the full rated working pressure of the choke manifold.

Hammer union fittings will be permitted externally to allow attachment of high-pressure lines for remedial operations. The hammer union fittings are to be welded or flanged where they tie into the choke manifold.

A pressure gauge (or other means) to measure the inlet pressure to the manifold must be provided. The manifold outlet for this device must be equipped with a flanged, studded or clamp hub type gate valve with 1-13/16" (46 mm) minimum bore.

Only right angle, targeted block turns must be used in the choke manifold and discharge piping. Target flanges must contain no lead, instead relying on the 4" deep pocket to provide a fluid cushion to resist erosion. All chokes must discharge directly into an erosion nipple. This nipple must be at least 3 ft (0.9 m) long. It must have a wall thickness at least as great as 3" (76 mm) XX heavy pipe.

A hydrate inhibition (i.e. glycol) injection system must be set up, if necessary, for use on 10M and 15M stacks.

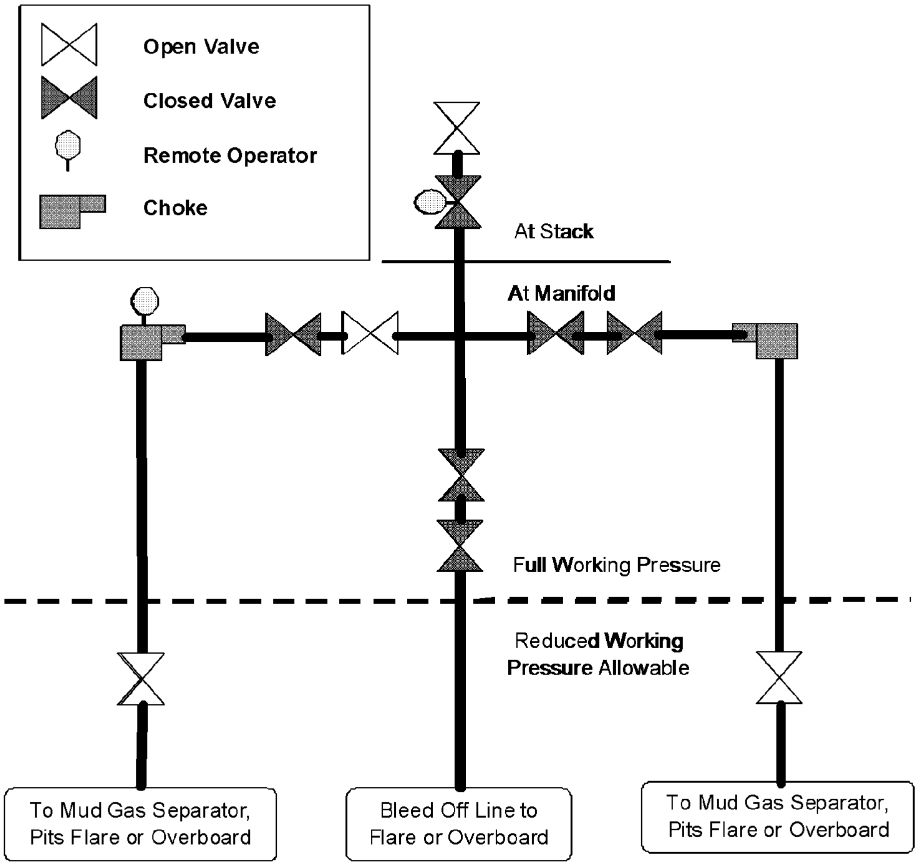
Under no circumstances will the kill or choke lines be utilized as hole fill-up lines.

The choke manifold must have the facility to accept high pressure fluids from the cementing unit or mud pumps, with appropriate valves to permit pumping into the choke and kill lines individually or simultaneously.

2.1.3 VALVE POSITIONS (DRILLING MODE)

Figure 9.4.1 below depicts an example of a manifold set up for a surface BOP stack. The valves are shown in their normal, open or closed position.

Figure 9.4.1, Manifold Set Up for Surface Stack



Closing the valve downstream of the choke on the choke manifold, instead of the valve upstream, is allowable provided that this downstream valve is rated to the BOP's full working pressure and equipped to allow opening under full working pressure.

2.2 FLOATING RIGS

The choke manifold assembly for floating rigs serves the same purpose and in general has the same components as those used on rigs with surface stacks.

2.2.1 FLOW PATHS

At least three flow paths must be provided that are capable of flowing well returns through conduits that are 3" (76 mm) nominal diameter or larger.

At least one flow path must be equipped with a remotely controlled, power-operated adjustable choke.

At least one flow path must be equipped with a manually operated adjustable choke.

One flow path may permit returns to flow directly to the discharge manifold or other downstream piping without passing through a choke. Two gate valves with full rated working pressure must be provided in this unchoked flow path.

2.2.2 COMPONENT SPECIFICS

The chokes, the two (2) valves controlling the unchoked discharge path and all equipment upstream of these items must have full rated working pressure and must be equipped with flanged, studded or clamp hub connections.

Two gate valves must be provided upstream of the choke in each choke flow path.

At least one gate valve must be installed downstream of each choke but ahead of any discharge manifold. This valve may or may not carry the full rated working pressure of the choke manifold.

A pressure transducer (or other means) to measure the inlet pressure to the manifold must be provided. The manifold outlet for this device must be equipped with a flanged, studded or clamp hub type gate valve with 1-13/16" (46 mm) minimum bore. The readout for the transducers must be at the remote choke control station.

Only right angle targeted block turns must be used in the choke manifold and discharge piping. Target flanges must contain no lead, instead relying on the 4" deep pocket to provide a fluid cushion to resist erosion.

The choke manifold must have the facility to accept high pressure fluids from the cementing unit or mud pumps, with appropriate valves to permit pumping into the choke and kill lines individually or simultaneously.

On systems with flare booms permanently installed, a permanent connection between the discharge manifold and flare boom must be installed.

A hydrate inhibitor (i.e. glycol) injection system must be set up for use, if necessary, on 10M and 15M choke/kill manifolds.

2.2.3 VALVE POSITIONS (DRILLING MODE)

Figure 9.4.2 below depicts an example of a manifold set up for a subsea BOP stack. The valves are shown in their normal, open or closed position:

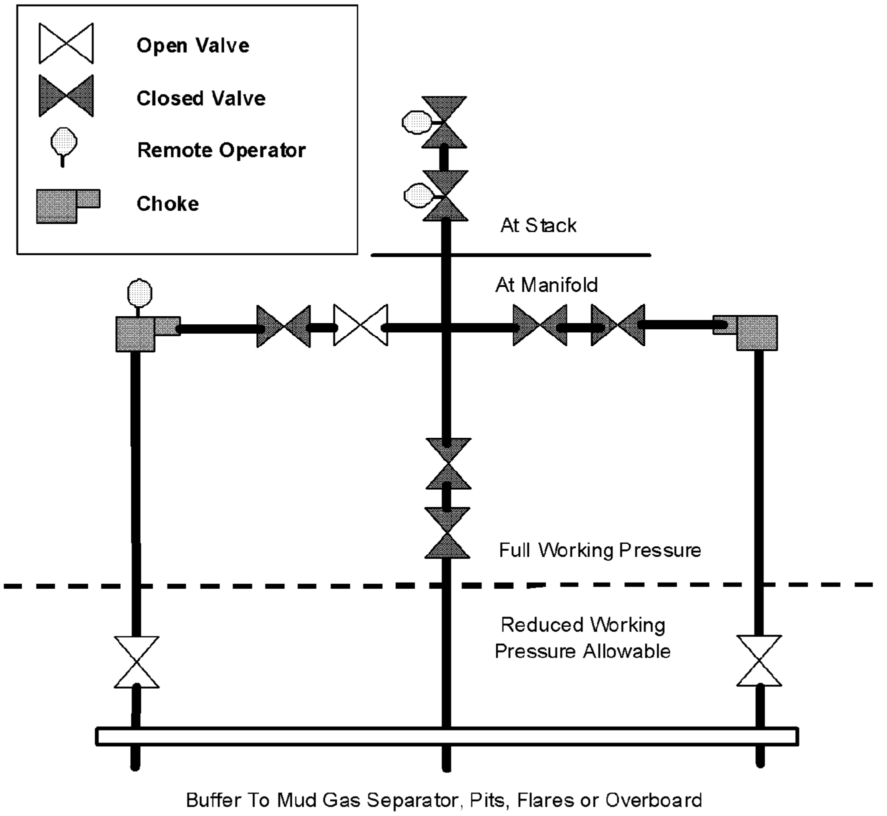
Closing the valve downstream of the choke on the choke manifold, instead of the valve upstream, is allowable provided that this downstream valve is rated to the BOP full working pressure and equipped to allow opening under full working pressure.

3 KILL MANIFOLD

The choke and kill (standpipe) manifold (surface and subsea) must be isolated by two isolation valves and have the capability of being connected to the cementing unit.

WELL CONTROL EQUIPMENT
CHOKE AND KILL MANIFOLD REQUIREMENTS

Figure 9.4.2, Manifold Set Up for Subsea Stack



1 SAFETY VALVES

A full opening safety valve (including a closing handle) with bottom connections, cross-overs or provisions to fit any section of drillstring, tubing or casing being handled must be available on the drill floor.

In addition:

- The valve must have a rated working pressure greater than or equal to the BOP stack.
- The connection is to fit the bottom connection of the topdrive or kelly.
- The outside diameter of the valve must be such that it may be run in the hole (an inside BOP must be pumped in the string or installed on top of the safety valve in order to run in the hole) with adequate clearance.
- This safety valve must be equipped with a means for easy handling to enable immediate connection to the drillstring in the event of a kick.

Examples of full opening safety valves are:

- Hydril Kelly Guard
- T.I.W
- S.M.F

1.1 INSIDE BOP'S

An Inside BOP (IBOP) is a surface installed back-pressure check valve. If this is a drop-in type, the landing sub must be positioned in the drillstring at or near the drill collars. There must be one such valve on the drill floor at all times.

Examples of IBOP's are:

- Gray valves.
- Hydril drop-in valve.

If a Gray valve is to be used, it must be ready for installation locked in the 'open' position.

If a drop-in type is used, the landing sub should be in the drillstring at or near the collars and the correct size dart must be on the drill floor in a protective box. The dart must be able to pass through all the restrictions above the landing sub.

1.2 FLOAT VALVE

Float valves (either plain or ported) must be used while drilling and opening hole prior to setting surface casing or any time the posted well control plan is to divert and can also be used in deeper sections of hole. In addition, all drillstrings used below surface casing must include either a float valve or landing sub for a drop-in valve.

Their function is to:

- Prevent sudden influx entry into drillstring.
- Prevent back flow of annular cuttings from plugging bit nozzles.

1.3 KELLY COCKS

Both the lower and upper kelly cocks must have a working pressure equal to or greater than the BOP's.

1.3.1 UPPER KELLY COCK

The upper kelly cock is a safety valve placed between the kelly joint and the swivel. The kelly cock must be closed if drillpipe pressure threatens to exceed the pressure rating of the washpipe packing or rotary hose.

It must be functioned (Close, Open) on every trip.

A special wrench to operate the upper kelly cock is required and must be kept on the drill floor.

1.3.2 LOWER KELLY COCK

A lower kelly cock (a full opening safety valve) must be installed immediately below the kelly.

It must be functioned (Close, Open) on every trip.

An appropriate wrench must be available on the drill floor for opening and closing it.

When a mud saver sub is used, it must be installed above the lower kelly cock.

1.4 TOPDRIVE SAFETY VALVES

When a topdrive system is in use there must be two safety valves included in the drilling hook up:

- The upper safety valve must be remotely operated.
- The lower safety valve must be manually operated.

Both upper and lower safety valves must be functioned (Close, Open) on every trip.

Should it become necessary to disconnect the TDS during well control operations, the lower safety valve must be backed out from the upper using the pipe handler. A sub to connect the upper safety valve to the drillpipe in use and a sub to connect the lower safety valve to the drillpipe in use must be installed temporarily. These subs must be available on the drill floor.

Any item in the string, which may need to be removed through the top of the string, such as a MWD drillpipe screen, must have an OD smaller than the lower safety valve ID.

1.5 STORM PACKER

A storm packer consists of a retrievable packer to support the weight of the drillstring and seal off the casing/drillpipe annulus and above it a combination back-off tool/valve to seal the ID of the drillstring.

When a subsea BOP stack is in use, consideration should be given to having storm packers available, to match the size and weight of casing and drillpipe in use.

1.6 MUD GAS SEPARATOR (MGS)

An atmospheric or low pressure separating vessel for handling gas-cut returns must be provided where blowout preventers are used.

The main purpose of this vessel is to segregate the gas from the mud and vent it a safe distance away from the drill floor.

It is essential to verify that the system is capable of handling the maximum amount of fluid and gas that could be produced by the well in the case of a severe kick. The relevant information of the well to be drilled should be obtained from the Operator and should be compared to the system capacity according to the Company.

Principal features include:

- A gas vent line exiting the top of the separator which must have a minimum internal diameter of 6" (152 mm). Venting above the crown is acceptable.

- A configuration such that a sufficient liquid seal is maintained to hold back anticipated pressure within the MGS during a kill operation. This is to avoid a blowthrough of free gas into the mud system.
- A facility must exist for bypassing the mud/gas separator in the event of system overload or malfunction. Well fluids should be directed to an emergency overboard line.
- A pressure gauge is required to monitor the pressure within the separator. A remote pressure transmitter may be used for this purpose but must be capable of operation without dependence on rig air supply or rig electrical power.

There are 4 critical design parameters:

- Separator capacity to segregate gas from the mud.
- Vent line capacity to vent free gas.
- Discharge line capacity to discharge degassed mud.
- Mud seal capacity to determine maximum MGS pressure. (Refer to Section 10 Subsection 12.)

1.7 VACUUM DEGASSER

The Vacuum de-gasser is designed to remove the small bubbles of gas that are left in the mud after the mud has been through the MGS.

The Vacuum de-gasser must be lined up at all times during the well control operation.

The gas exhaust line should not be connected to the MGS vent line. In the event the exhaust line is connected to the MGS vent line, then a liquid seal must always be maintained in the MGS whenever the vacuum degasser is being used, and should be highlighted in the rig specific operating procedures. Also, the arrangements should be risk-assessed to ensure that there is no potential for gas to vent back through the degasser when using the MGS with the vacuum degasser off.

It is important that the Vacuum de-gasser is working properly and as such it should be tested every tour.

1.8 SHOOTING NIPPLE

A shooting nipple (or open hole riser) connects the BOP to wireline pressure control equipment, and is used when a well has the potential to become underbalanced.

If a shooting nipple is to be used then it shall be held in place either by a set of pipe rams (with blind shears below) or fitted to a purpose-built device mounted on top of the annular.

If held in a set of rams, confirmation must be received from the manufacturer that the size of the stop collar on the bottom of the shooting nipple provides an adequate metal to metal contact area to cater the type and size of rams to be used and the expected pressures. Shooting nipples with welded stop collars must never be used, only shooting nipples with threaded stop collars are acceptable. Chains or slings must not be used to retain the assembly.

All shooting nipples are to be provided by the Client. Non-certified or home-made shooting nipples will not be used on a Transocean rig in any operations.

Any shooting nipple used on a Transocean rig will be purpose-built and tested by approved manufacturers and suppliers. Under no circumstance will Transocean personnel provide, manufacture or modify shooting nipples for use on a Transocean rig.

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1 GENERAL

All surface and subsea system stump tests are to be conducted with water or anti-freeze solution. After the BOPs have been landed, pressure tests may be performed with the drilling fluid that is being used to drill the well. All pressure tests are to be conducted with applied surface pressure (not wellbore pressure).

2 PRESSURE TEST FREQUENCY

Surface BOPs:

The pressure test of all BOPs, annulars, wellbore components and their connections, BOP operating unit, choke manifold, kill and choke lines, standpipe manifold, kelly and kelly cocks, safety valves and IBOPs must be made:

- **Prior to installation on wellhead where possible.**
- **When any component change or repair is made.**
- **After installation on wellhead (if not previously stump tested).**
- **Prior to drilling into a suspected high pressure zone.**
- **Prior to initial opening of drill stem test tools.**

The pressure test of affected components must be made:

- **After installation on wellhead (connection to wellhead only, if previously stump tested).**
- **When bonnets have been opened solely for the purpose of changing rams prior to running casing; a body test to ensure the integrity of the bonnet seals will suffice.**
- **After disconnect of pressure containing seals.**

While testing Surface BOP on wellhead, the wellhead side outlet immediately below the test plug shall be opened and continuously monitored for leakages of test fluid past the seals or flow from the well. Test fluids pumped need to be accurately monitored to prevent possible hydraulic lift of testing tools and / or casing / downhole damage. The testing should be carried out using an open hollow bore test plug to allow flow up the pipe if test plug seal fails.

Note: If testing is conducted in the casing with a cup tester, the test pressure should not exceed 80% of the casing burst pressure.

Subsea BOPs:

The pressure test of all BOPs, annulars, wellbore components and their connections and BOP control / operating system must be made:

- Prior to running the assembled BOP stack:
- When any component change or repair is made.

The pressure test of all BOPs, annulars, wellbore components and their connections, marine riser, BOP operating unit, choke manifold, kill and choke lines, standpipe manifold, Kelly and Kelly cocks, safety valves and IBOP's must be made:

- When BOP stack is run and latched onto the wellhead. If BOP has been stump tested prior to run, it is not necessary to duplicate pressure tests already carried out. However it is required to pressure test the wellhead connector (and LMRP connector if appropriate).
- Prior to drilling into a suspected high pressure zone.
- Prior to initial opening of drill stem test tools.

Surface and Subsea BOPs:

The period between pressure tests of the BOPs (excluding blind/shear rams), annulars, and related equipment must not exceed a maximum of 21 days.

As a minimum, blind/shear rams are to be tested at least every 42 days. Where applicable, they should be tested prior to drilling out after each casing string has been set.

The stump test is valid for up to 21 days prior to installation on the wellhead. The 21 day testing interval starts upon installation on the wellhead.

BOPs (excluding annulars), choke manifolds, and choke and kill lines should be pressure tested on the surface to the rated working pressure every 180 days and must be tested at least every 365 days or as near to this as operations allow.

Annulars should be tested to 70% of the rated working pressure every 180 days and must be tested at least every 365 days. Following shop repairs for major overhaul, annulars must be pressure tested to 100% of working pressure; if shop repairs include welding on the body or other pressure-containing components, a shell test must be performed to API 16A requirements.

Every rig must have written BOP pressure testing procedures supplemented with stack and manifold diagrams. All pressure tests must be fully documented on the rig's BOP equipment test sheets. Tests performed must be recorded in the IADC report.

3 EQUIPMENT TO BE PRESSURE AND FUNCTION TESTED

The following equipment must be tested:

- **All components of the BOPs, annulars, wellhead components and their connections must be function and pressure tested. Ram locks must be pressure tested with the closing pressure bled off.**
- **There is no requirement to function test the following subsea:**
  - **Release or latching type components (choke, kill, riser and wellhead connectors).**
  - **Ram locking devices.**
  - **Cameron Super Shear Rams**
- **All control systems and back-up control systems such as EDS, autoshear, deadman, EH, ROV stabs and valves, and acoustic pods must be function tested on surface.**
- **All choke manifold valves, kill and choke lines and valves on the side outlets must be function and pressure tested.**
- **All topdrive safety valves/kelly and kelly cocks, must be pressure tested to the lesser of the following:**
  - **Kelly cock rated working pressure.**
  - **Drillpipe internal yield pressure.**
  - **BOP stack rated working pressure.**
- **The standpipe manifold, tested to its rated working pressure.**
- **The chiksans must be tested to specified test pressure before use.**

4 PRESSURE TEST VALUES

4.1 LOW PRESSURE TEST

200-300 psi (1380-2070 kPa; 13.8-20.7 bar) for 5 minutes prior to each high pressure test.

No visible leakage is allowed.

4.2 HIGH PRESSURE TEST

Ram type preventers and related control equipment (including the choke manifold) must be tested to the anticipated surface pressure.

If the cup-type tool is used, the additional load on the drillpipe due to the piston effect needs to be determined and checked against pipe strength.

Annulars must be tested to 70% of the rated working pressure or maximum anticipated wellhead pressure, whichever is less (subject to limitations imposed by the Operator such as wellhead pressure rating, casing burst pressure, etc.).

All high pressure tests must be conducted for at least 5 minutes.

No visible leakage is allowed.

A 5-minute stabilized straight line is the acceptable minimum.

5 FUNCTION TEST FREQUENCY

5.1 SURFACE BOPs

All rams, annulars, diverters, valves, etc., must be function tested at the following frequencies:

- **Upon installation on the wellhead from the Driller's and the remote control panel.**
- **Every week or during the first trip after the 7 day interval. Under no circumstance will this interval exceed a maximum of 14 days.**

5.2 SUBSEA BOPs

All rams, ram locks, annulars, subsea actuated gate valves, diverters, or other items run subsea must be function tested at the following frequencies:

- **Prior to running the assembled BOP stack:**
  - **Function test all components with both control pods from the Driller's and remote control panels, whether or not repairs have been made.**
  - **Function test ram locking devices.**
  - **Function test all functions on the hose reel control panels.**

- **Function test the operation of the back-up control systems: ROV stabs and valves, EDS, autoshear, deadman, emergency recovery systems, EH and acoustic pod.**

All rams, annulars, subsea actuated gate valves, diverter, other items run subsea, choke manifold, kill and choke lines, standpipe manifold, kelly and kelly cocks, safety valves and IBOPs must be function tested at the following frequencies:

- **When BOP stack is run and latched onto the wellhead:**
  - **When first latched. This test must include the function of all components, with the exception of Cameron Super Shear rams and any equipment whose operation may affect the pressure integrity of the system (e.g. wellhead and riser connectors, choke and kill line stabs, ram locks, etc.), using both control pods from the driller's and remote control panels.**
- **Every week, or during the first trip after the 7-day interval. This interval will not exceed 14 days (Section 1 Subsection 2 Item 1.11).**

6 ACCUMULATOR TESTS

Low fluid level alarms must be tested weekly.

6.1 SURFACE BOPs

Accumulator performance tests must be done after initial installation on the wellhead.
This test must include:

- **Charge the system with fluid to its working pressure.**
- **Switch off the accumulator pumps.**
- **Close the annular, all rams (except blind or blind/shear rams) and open all HCR valves (against zero wellbore pressure).**

Observe that there is at least 200 psi (1380 kPa/13.8 bar) above the pre-charge pressure on the accumulator gauge.

Switch on all the accumulator pumps. Record accumulator recharging time to maximum working pressure, which should be less than 15 minutes.

Report all recorded information on BOP test forms.

6.2 SUBSEA STACKS

Accumulator performance tests must be done prior to installation on the wellhead. Two methods of determining accumulator compliance with the capacity requirements can be used.

- **Surface accumulators are sufficient to meet this test.**
- **A combination of surface and subsea accumulator bottles meets the requirement.**

Surface capacity systems should be tested with subsea bottles isolated. The combined system requires that the subsea bottles be pre-charged and/or isolated so that their capacity provides the usable volume as if the bottles were actually subsea. Both system designs and these tests demonstrate minimum accumulator performance capacity subsea.

This test must include:

- **Charge the system with fluid to the working pressure of system.**
- **Switch off the accumulator charging pumps.**
- **Install the drill string or test joint in the BOP and LMRP.**
- **Close one annular, close all rams (a maximum of 4, except blind/shear rams), function all ram locks, and open all subsea actuated gate valves (against zero wellbore pressure.)**
- **Open one annular, unlock and open all rams (a maximum of 4, except blind/shear rams) and close all subsea actuated gate valves (against zero wellbore pressure).**
- **Monitor accumulator pressure closely. Confirm that there is at least 200 psi (1380 kPa, 13.8 bar) above the precharge on the accumulator gauge.**
- **Switch on all the accumulator pumps. Record accumulator recharging time, which should be less than 15 minutes.**

Report all recorded information on BOP Test Forms.

7 TESTING EQUIPMENT

Test equipment must include a chart recorder and gauges. All testing equipment must be controlled and verified periodically – maximum interval for verification will be yearly. All testing pressure gauges must have a minimum face diameter of 4.5 inches.

APPENDIX

ABBREVIATIONS AND DEFINITIONS

ABBREVIATIONS

APL	Annular Pressure Losses
API RP	American Petroleum Institute Recommended Practice
Bbls	Barrels
BHA	Bottomhole Assembly
BHP	Bottomhole Pressure
BPL	Bit & Nozzle Pressure Losses
BOP	Blowout Preventer
BRT	Below Rotary Table
Ca	Annular Capacity
CLPL	Choke Line Pressure Losses
CSG	Casing
d_c	Drilling Exponent (corrected)
DC	Drillcollar
DP	Dynamic Positioning or Drill Pipe
DSPL	Drillstring Pressure Losses
DST	Drillstem Test
ECD	Equivalent Circulating Density
EMW	Equivalent Mud Weight
ESD	Equivalent Static Density
FCPadm	Maximum Admissible Final Circulating Pressure
FCP	Final Circulating Pressure
FIT	Formation Integrity Test
Gfb	Formation Breakdown Pressure Gradient
Gi	Influx Pressure Gradient
Gmud	Pressure Gradient of Mud
GPM	Gallons Per Minute
Hi	Height of Influx
HCR	Hydraulic Controlled Remote
HDIS	Hydril Drop In Sub
HP/HT	High Pressure/High Temperature
H2S	Hydrogen Sulphide
IADC	International Association of Drilling Contractors
ICP	Initial Circulating Pressure
ID	Internal Diameter
KT	Kick Tolerance
LCM	Lost Circulation Material
LMRP	Lower Marine Riser Package
LOT	Leak Off Test
LWD	Logging While Drilling
MAASP	Maximum Allowable Annular Surface Pressure
MAMW	Maximum Allowable Mud Weight

APPENDIX
ABBREVIATIONS AND DEFINITIONS
ABBREVIATIONS

MD	Measured Depth
MGS	Mud Gas Separator
MODU	Mobile Offshore Drilling Unit
MSL	Mean Sea Level
MWD	Measurement While Drilling
MW	Mud Weight
NMAASP	New MAASP with KMW
NRV	Non Return Valve
NSDPP	New Static Drill Pipe Pressure
OBM	Oil Based Mud
OD	Outside Diameter
OIM	Offshore Installation Manager
OMW	Original Mud Weight
Pa	Annulus pressure
Pchoke	Choke Pressure
Pdp	Drillpipe pressure
Pf	Formation pressure
Ph	Hydrostatic pressure
Pi	Hydrostatic pressure of influx
Plot	Leak off test pressure
POBM	Pseudo Oil Based Mud
POOH	Pull Out of Hole
PPB	Pounds Per Barrel
PPG	Pounds Per Gallon
PV	Plastic Viscosity
RIH	Run Into the Hole
RKB	Rotary Kelly Bushing
ROV	Remote Operated Vehicle
ROP	Rate of Penetration
RPM	Revolutions per Minute
RT	Rotary Table
SCR	Slow Circulating Rate
SCRP	Slow Circulating Rate, Pressure
SCRmax	Circulating Rate when CLPL < SICP
SCRmin	Circulating Rate when CLPL < New MAASP
SG	Specific Gravity
SICP	Shut-in Casing Pressure
SIDPP	Shut-in Drill Pipe Pressure
SPL	Surface Pressure Loss
SSTT	Subsea Test Tree
SPM	Strokes per Minute

APPENDIX
ABBREVIATIONS AND DEFINITIONS
ABBREVIATIONS

SWF	Shallow Water Flow
TD	Total Depth
TDS	Top Drive System
TVD	True Vertical Depth
TVDshoe	Casing Shoe TVD
TVDwp	True vertical depth of open hole weak point
UBD	Underbalanced Drilling
WBM	Water Base Mud
WOB	Weight on Bit
WOC	Wait On Cement
YP	Yield Point

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Abnormal Pore Pressure - Pressure of a formation which exceeds the normal pressure expected at a given depth.

Annular Pressure Loss (APL) - Pressure loss caused by the flow of fluid up the annulus.

Bleeding - Controlled release of fluids from a closed and pressured system.

Blowout - An uncontrolled flow of gas, oil or other formation fluids from a wellbore.

Bottom Hole Pressure - The pressure exerted by a column of fluid contained in the wellbore.

Bullheading - A term for pumping into a shut-in well without returns.

Casing Burst Pressure - The amount of internal pressure that causes the wall of the casing to fail.

Casing Seat - The lowest point in a well at which casing is set.

Choke - A variable diameter orifice installed in a line through which high pressure well fluids can be restricted or released at a controlled rate.

Choke Line - The high pressure piping between blowout preventer outlets or wellhead outlets and the choke manifold.

Choke Manifold - The system of valves, chokes and piping to control flow from the annulus and regulate pressures in the drillpipe/annulus flow system.

Closing Unit - The assembly of pumps, valves, lines, accumulators and other items necessary to open and close the blowout preventer equipment.

Density - The weight per unit volume of a substance.

Differential Pressure - Difference between wellbore fluid pressure and pore pressure or the opposing internal and external forces acting on equipment.

Drilling Break - A significant increase in the rate of penetration by the drill bit. It may indicate that the bit has penetrated a high pressure zone, thereby warning of the possibility of a kick.

Displacement - The volume of steel in the tubulars and tools inserted and/or withdrawn from the wellbore.

Drillpipe Safety Valve - A full-opening valve which, when installed in the drillstring, can be closed to prevent flow through the bore of the drillpipe.

Equivalent Circulating Density (ECD) - The effective density at any depth created by the sum of the total hydrostatic pressure plus annular pressure loss.

Equivalent Mud Weight (EMW) - A pressure exerted at a depth of interest which is converted into a density.

Final Circulating Pressure - Drillpipe pressure required to circulate at a selected kill rate, adjusted for the increase in kill drilling fluid density above the original drilling fluid density.

Flow check - A flow check is the observation of the well without circulation. Flow checks are made to determine whether or not the well is flowing. The duration of a flow check must be whatever time necessary to determine without question whether the well is static or flowing.

Flow Rate - The volume of a fluid passing through any conductor, such as pipe or tubing, per unit of time.

Formation Integrity Test - Application of pressure by superimposing a surface pressure on a fluid column in order to determine the ability of a subsurface zone to withstand a certain hydrostatic pressure.

Formation Pressure - Pressure exerted by fluids within the pore spaces of a formation.

Fracture Gradient - The pressure gradient at which the formation accepts whole fluid from the wellbore.

Geothermal Gradient - The rate at which subsurface temperature increases with depth. The earth averages 1°C per 33m (1°F per 60 ft) but may be considerably higher.

Glycol (Ethylene) - A colourless liquid mixed with water to lower the freezing temperature. Used as a desiccant in removing water from gas.

Hard Shut-In - To close in a well by closing a blowout preventer with the choke and/or choke line valve(s) closed.

Hydrostatic Pressure - The pressure exerted by a column of fluid at rest.

Initial Circulating Pressure - The sum of the drillpipe pressure at the selected kill rate and the shut-in drillpipe pressure.

Inside Blowout Preventer - A device that can be installed in the drill string that acts as a check valve, allowing drilling fluid to be circulated down the string but prevents back flow.

Intermediate String - Usually set in a transition zone of an abnormally pressured formation or used to protect weak formations (loss circulation zones, hole sloughing, caving formations) and to provide pressure containment. Cementing program may be designed to isolate hydrocarbon zones or flowing salt sections.

Kick (Influx) - The entry of oil, gas or water into the wellbore. When the bottom hole pressure becomes less than formation pressure and the permeability is great enough, formation fluid will enter the wellbore causing a kick.

Kick Assembly - Assembly of full opening safety valve(s), circulating head and hose used to circulate where pressures exceed the rating of the Top Drive or Kelly.

Kill Line - A high-pressure fluid line connecting the mud pump and the wellhead at some point below a blowout preventer. This line allows heavy drilling fluids to be pumped into the well or annulus with the blowout preventer closed.

Kill Rate - A predetermined circulating rate used to circulate out a kick and usually a fraction of the circulating rate used while drilling.

Lag Time - Bottoms-up circulation time. Time it takes for the mud to reach surface from bit at a given pumping rate while circulating on bottom.

Leak-Off Test Pressure - Pressure imposed at surface on the fluid column to determine the pressure at which a formation will start to take fluid.

Liner - Installed as an intermediate casing string to permit deeper drilling, to separate the productive zones from other reservoir formations or for testing purposes. Usually cemented to top of liner.

Marine Conductor - A pipe driven, jetted or cemented in pre-drilled hole, to provide structural strength, to cover very soft formations below the sea bottom, to serve as a circulation system for the drilling fluid and to guide the drilling and casing strings into the hole.

Maximum Allowable Annular Surface Pressure (MAASP) - The surface pressure which if exceeded, may either cause loss of mud into a formation below the casing shoe or cause casing or other equipment to fail, whichever pressure is least.

Mud Gas Separator - An atmospheric or low-pressure vessel for separating the gas from liquid in well returns.

Normal Formation Pressure - Formation pressure equal to the pressure exerted by a vertical column of water with a salinity normal for the geographic area.

Non-Return Valve (Check Valve) - Device used to restrict the flow of fluid to only one direction.

Overbalance - The amount by which pressure exerted by the hydrostatic head of fluid in the wellbore exceeds formation pressure.

Overburden Pressure - The pressure on a formation generated by the combined weight of the rock and fluid above that formation.

Permeability - The ability of fluid to flow from one pore space to another.

Pit Volume Indicator - A device installed in drilling fluid tanks to register the fluid level.

Porosity - The spaces within a rock. The ratio of the volume of interstices of a material to its total volume.

Production String - Installed to separate the productive zones from other reservoir formations or for testing purposes.

Relief Well - An offset well drilled to intersect the subsurface formation to combat blowout.

SCR max - The circulating rate at which the chokeline friction loss is equal to the shut-in casing pressure (SICP).

SCR min - The circulating rate at which the choke line friction loss is equal to the maximum allowable annular surface casing pressure (MAASP).

Space Out - Procedure conducted to position a pre-determined length of drillpipe above the rotary table so that a tool joint is located above the rams on which the drillstring is to be suspended and that no tool joint is opposite a set of rams after the drillpipe is hung off.

Specific Gravity - The ratio of the weight of a given volume of a substance at a given temperature to the weight of an equal volume of fresh water at the same temperature.

Subnormal Pore Pressure - Pressure of a formation which is below normal pressure expected at a given depth.

Surface Casing - Installed to provide blowout protection, seal off shallow sands and prevent loss of circulation. This string is normally cemented to surface or at least up to the shoe of the conductor string.

Swabbing - The lowering of the hydrostatic pressure in the wellbore due to upward movement of tubulars and/or tools.

Underbalance - The amount by which formation pressure exceeds pressure exerted by the hydrostatic head of fluid in the wellbore.

Underground Blowout - Uncontrolled flow of formation fluids entering the wellbore at one point and leaving the wellbore at any point other than the surface. The flow is most likely to travel up the wellbore before exiting, but can on occasion travel down the wellbore to the receiving formation.

Viscosity - A measure of the internal friction or the resistance of a fluid to flow.

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NOTE: Blank forms in oilfield units are made available in the Manual, incase internet access is not available. However, Excel program of kill sheets in Oilfield, Metric and SI units are available on the link below at the Well Operations Group homepage.
http://www.rigcentral.com/hqs/pt/well_operations_group/well_control1.asp

In addition to the forms included in this manual, the following forms are available at
http://www.rigcentral.com/hqs/pt/well_operations_group/Well_Control.asp

- Trip Sheet
- Accumulator Function Test Worksheet
- Accumulator Closing Test Worksheet
- BOP
- Test Form

If you do not have access to the intranet, contact the Well Operations Group in Houston.

1 TRANSOCEAN KILL SHEETS

The following 4 blank examples (oilfield units) are included:

Surface BOP: Vertical Well and Deviated Well

Subsea BOP: Vertical Well and Deviated Well

Wait & Weight Method
(Calculations required for completing Kill Sheet)

1. Calculate The Kill Mud Weight Using The Stabilized SIDPP.

KMW (ppg) = [SIDPP (psi) ÷ 0.052 ÷ TVD (ft)] + OMW (ppg)

KMW (kg/m^3) = [SIDPP (kPa) x 102 ÷ TVD (m)] + OMW (kg/m^3)

KMW (kg/l) = [SIDPP (bar) ÷ 0.0981 ÷ TVD (m)] + OMW (kg/l)

A trip margin will not be included in the calculation for kill mud weight. The main reason for this is to avoid any additional well pressure that could result in formation breakdown (refer to Section 5.4.8)

2. Calculate Initial Circulating Pressure.

ICP = SCRP + SIDPP

3. Calculate Final Circulating Pressure.

FCP = SCRP x (KMW ÷ OMW)

4. Calculate surface to bit strokes.

$$\text{No. of strokes} = \frac{\text{Drillstring Volume}}{\text{Pump output}}$$

5. Calculate the time to pump from surface to the bit.

$$\text{Time (mins)} = \frac{\text{Total strokes from surface to bit}}{\text{Strokes per minute}}$$

6. Once the preceding calculations are completed, plot pump pressure versus pump strokes and time on the drillpipe pressure schedule.

- Plot ICP at left of graph.
- Plot FCP at right of graph.
- Connect points with a straight line.
- The pressure drop per increment can be calculated as follows:

$$\text{Pressure drop per pump stroke} = \frac{\text{ICP - FCP}}{\text{Surface to bit strokes}}$$

Multiplying the result by '100' will provide the required pressure drop for every 100 strokes of kill mud pumped.

7. To determine when the influx is inside the shoe:

$$\text{Bit to Shoe strokes} = \frac{\text{Bit to shoe volume}}{\text{Pump output}}$$

8. To determine when the kill mud is at surface:

$$\text{Bit to Surface strokes} = \frac{\text{Bit to surface volume}}{\text{Pump output}}$$

APPENDIX
FORMS AND PROCEDURES
KILL SHEET FORMS

Transocean

Surface BOP Vertical Well Kill Sheet (Oilfield Units)

Page 1 of 2

DATE: ____________

RIG: ____________

THIS SHEET CAN BE PRINTED AND USED AS A BLANK OR AS A SPREADSHEET IN WHICH CASE INPUT DATA INTO THE COLOURED CELLS ONLY

FORMATION STRENGTH DATA:

SURFACE LEAK-OFF PRESSURE FROM

FORMATION STRENGTH TEST (A) ______ psi

DRILLING FLUID DENSITY AT TEST (B) ______ ppg

MAXIMUM ALLOWABLE DRILLING FLUID DENSITY =

$$(B) + \frac{(A)}{\text{SHOE T.V. DEPTH} \times 0.052} = (C) \text{ ______ ppg}$$

INITIAL MAASP =

((C) - CURRENT DENSITY) x SHOE T.V. DEPTH x 0.052

= ______ psi

CURRENT WELL DATA:

CURRENT DRILLING FLUID:

DENSITY ______ ppg

CASING SHOE DATA:

SIZE ______ inch

M. DEPTH ______ feet

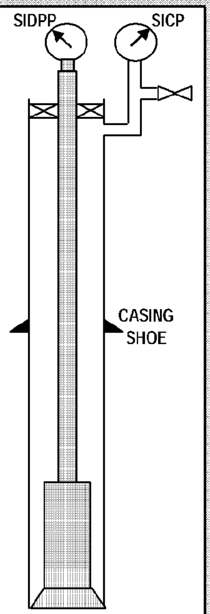
T.V. DEPTH ______ feet

HOLE DATA:

SIZE ______ inch

M. DEPTH ______ feet

T.V. DEPTH ______ feet



PUMP NO. 1 DISPL	PUMP NO. 2 DISPL
bbls / stroke	bbls / stroke

SLOW PUMP RATE DATA:	(PL) DYNAMIC PRESSURE LOSS [psi] PUMP NO 1	PUMP NO 2
SPM		
SPM		

TO CALCULATE AUTOMATICALLY, ENTER PUMP NO HERE ______ PUMP RATE HERE ______ AND PRESSURE LOSS ______

PRE-RECORDED VOLUME DATA	LENGTH feet		CAPACITY bbls/ft		VOLUME barrels		PUMP STROKES strokes	TIME minutes
DRILLPIPE		x		=			VOLUME / PUMP DISPLACEMENT =	PUMP STROKES / SLOW PUMP RATE =
HEVI WALL DRILL PIPE		x		=		+		
DRILL COLLARS		x		=		+		
DRILL STRING VOLUME					(D) bbls		(E) strokes	minutes
DC x OPEN HOLE		x		=				
DP / HWDP x OPEN HOLE		x		=		+		
OPEN HOLE VOLUME					(F) bbls		strokes	minutes
DP x CASING		x		=	(G) bbls		strokes	minutes
TOTAL ANNULUS VOLUME					(F+G) = (H) bbls		strokes	minutes
TOTAL WELL SYSTEM VOLUME					(D+H) = (I) bbls		strokes	minutes
ACTIVE SURFACE VOLUME					(J) bbls		strokes	
TOTAL ACTIVE FLUID SYSTEM					(I+J) bbls		strokes	

APPENDIX
FORMS AND PROCEDURES
KILL SHEET FORMS

Transocean

Surface BOP Vertical Well Kill Sheet (Oilfield Units)

Page 2 of 2

DATE: ____________________

RIG: ____________________

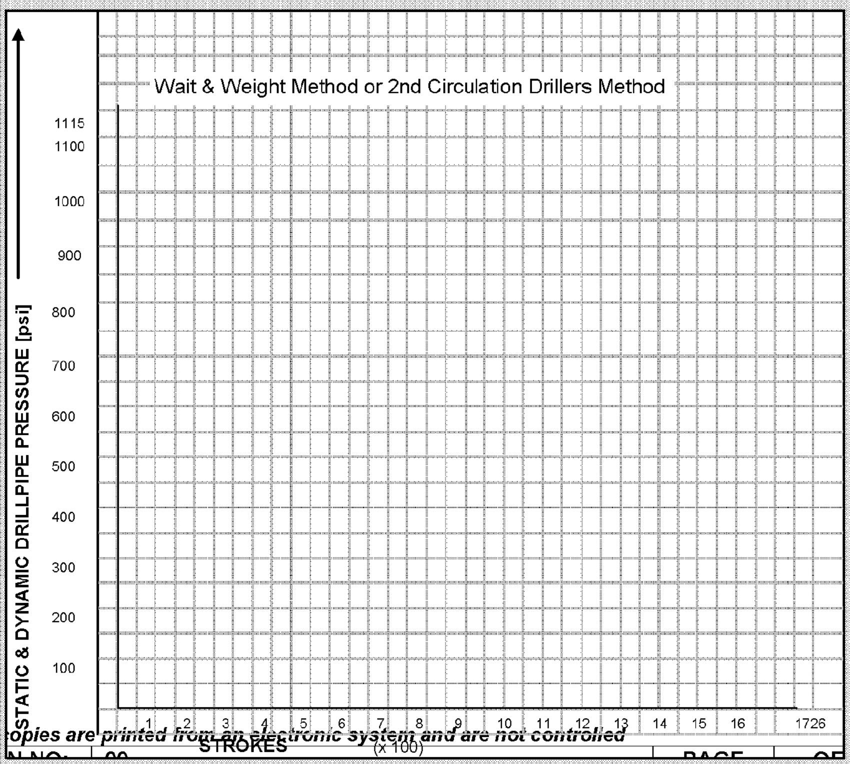
KICK DATA

SIDPP [ ] psi   SICP [ ] psi   PIT GAIN [ ] bbls

KILL FLUID DENSITY KMD	CURRENT DRILLING FLUID DENSITY + SIDPP / TVD x 0.052 + ________ / x 0.052 =	________ ppg
INITIAL CIRCULATING PRESSURE ICP @ SPM	DYNAMIC PRESSURE LOSS + SIDPP + =	________ psi
FINAL CIRCULATING PRESSURE FCP @ SPM	KILL FLUID DENSITY / CURRENT DRILLING FLUID DENSITY x DYNAMIC PRESSURE LOSS ________ x =	________ psi

(J) = ICP - FCP = - = psi   (J) x 100 / (E) = ________ / x 100 = psi / 100 strokes

STROKES	PRESSURE (psi)



APPENDIX
FORMS AND PROCEDURES
KILL SHEET FORMS

Transocean

Surface BOP Deviated Well Kill Sheet (Oilfield Units)

Page 1 of 3

DATE:

RIG:

THIS SHEET CAN BE PRINTED AND USED AS A BLANK OR AS A SPREADSHEET. IN WHICH CASE INPUT DATA INTO THE COLOURED CELLS ONLY

FORMATION STRENGTH DATA:

SURFACE LEAK-OFF PRESSURE FROM FORMATION STRENGTH TEST **(A)** psi

DRILLING FLUID DENSITY AT TEST **(B)** ppg

MAX. ALLOWABLE DRILLING FLUID DENSITY =

(B) + $\frac{\textbf{(A)}}{\text{SHOE T.V. DEPTH} \times 0.052}$ = **(C)** ppg

INITIAL MAASP =

((**C**) - CURR. DENS.) x SHOE T.V. DEPTH x 0.052

= psi

CURRENT WELL DATA:

DRILLING FLUID DATA:

DENSITY ppg

DEVIATION DATA:

KOP M.D. ft

KOP T.V.D. ft

EOB M.D. ft

EOB T.V.D. ft

CASING SHOE DATA:

SIZE in

M. DEPTH ft

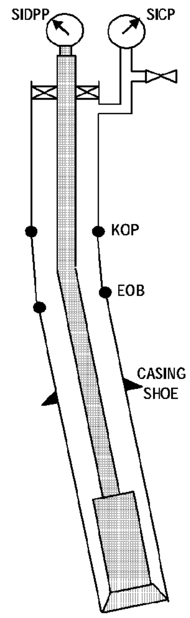
T.V. DEPTH ft

HOLE DATA:

SIZE in

M. DEPTH ft

T.V. DEPTH ft



PUMP NO. 1 DISPL	PUMP NO. 2 DISPL
bbl / stroke	bbl / stroke

SLOW PUMP RATE DATA	(PL) DYNAMIC PRESSURE LOSS	
	PUMP NO 1	PUMP NO 2
SPM	psi	psi
SPM	psi	psi

TO CALCULATE AUTOMATICALLY, ENTER PUMP NO. HERE   PUMP RATE HERE   AND PRESSURE LOSS

PRE-RECORDED VOLUME DATA	LENGTH ft	CAPACITY bbls/ft	VOLUME bbl	PUMP STROKES stks	TIME minutes
DP - SURFACE TO KOP	x	=		(L) stks	
DP - KOP TO EOB	x	=	+	(M) stks	
DP - EOB TO BHA	x	=	+	(N1) stks	
HEVI WALL DRILL PIPE	x	=	+	(N2) stks	
DRILL COLLARS	x	=	+	(N3) stks	
DRILL STRING VOLUME			(D) bbl	stks	min
DC x OPEN HOLE	x	=			
DP / HWDP x OPEN HOLE	x	=	+		
OPEN HOLE VOLUME			(F) bbl	stks	min
DP x CASING	x	=	(G) +	stks	min
TOTAL ANNULUS VOLUME		(F+G) = (H)	bbl	stks	min
TOTAL WELL SYSTEM VOLUME		(D+H) = (I)	bbl	stks	min
ACTIVE SURFACE VOLUME		(J)	bbl	stks	
TOTAL ACTIVE FLUID SYSTEM		(I+J)	bbl	stks	

APPENDIX

FORMS AND PROCEDURES

KILL SHEET FORMS

Transocean

Surface BOP Deviated Well Kill Sheet (Oilfield Units)

Page 2 of 3

DATE: ____________

RIG: ____________

KICK DATA	
SIDPP ______ psi	SICP ______ psi PIT GAIN ______ bbl
KILL FLUID DENSITY KMD	CURRENT DRILLING FLUID DENSITY + SIDPP / (TVD x 0.052) + ______ / (x 0.052) = ______ ppg
INITIAL CIRC. PRESS. ICP @ SPM	DYNAMIC PRESSURE LOSS + SIDPP + = ______ psi
FINAL CIRCULATING PRESSURE FCP @ SPM	KILL FLUID DENSITY / CURRENT DRILLING FLUID DENSITY x DYNAMIC PRESSURE LOSS ______ x = ______ psi
DYNAMIC PRESSURE LOSS AT KOP (O)	PL + [(FCP - PL) x KOPMD / TDMD] = + [[-] x ______] = ______ psi
REMAINING SIDPP AT KOP (P)	SIDPP - [(KMD - OMD) x 0.052 x KOPTVD] = - [[-] x *0.052* x] ______ *psi*
CIRCULATING PRESS. AT KOP (KOP CP)	(O) + (P) = + = ______ psi
DYNAMIC PRESS. LOSS AT EOB (R)	PL + [(FCP-PL) x EOBMD / TDMD] = + [[-] x ______] = ______ psi
REMAINING SIDPP AT EOB (S)	SIDPP - [(KMD - OMD) x 0.052 x EOBTVD] = - [[-] x *0.052* x] ______ psi
CIRCULATING PRESSURE AT EOB (EOB CP)	(R) + (S) = + = ______ psi
(T) = ICP - KOP CP = - = psi	(T) x 100 / (L) = ______ x 100 = psi / 100 strokes
(U) = KOPCP - EOBCP = - = psi	(U) x 100 / (M) = ______ x 100 = psi / 100 strokes
(V) = EOBCP - FCP = - = psi	(V) x 100 / (N1+N2+N3) = ______ x 100 = psi / 100 strokes

Transocean

Surface BOP Deviated Well Kill Sheet (Oilfield Units)

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DATE: ____________

RIG: ____________

Wait & Weight Method or 2nd Circulation Driller's Method

STROKES	PRESSURE [psi]

STATIC & DYNAMIC DRILL PIPE PRESSURE [psi]

STROKES (x100)

APPENDIX

FORMS AND PROCEDURES

KILL SHEET FORMS

Transocean

Subsea BOP Vertical Well Kill Sheet (Oilfield Units)

Page 1 of 2

DATE:

RIG:

THIS SHEET CAN BE PRINTED AND USED AS A BLANK OR AS A SPREADSHEET. IN WHICH CASE INPUT DATA INTO THE COLOURED CELLS ONLY

FORMATION STRENGTH DATA:

SURFACE LEAK-OFF PRESSURE FROM FORMATION STRENGTH TEST (A) ______ psi

DRILLING FLUID DENSITY AT TEST (B) ______ ppg

MAXIMUM ALLOWABLE DRILLING FLUID DENSITY =

$$(B) + \frac{(A)}{\text{SHOE T.V. DEPTH} \times 0.052} = (C) \text{ ______ ppg}$$

INITIAL MAASP =

((C) - CURRENT DENSITY) x SHOE T.V. DEPTH x 0.052 = ______ psi

CURRENT WELL DATA:

SUBSEA BOP DATA:

MARINE RISER LENGTH ______ feet

CHOKELINE LENGTH ______ feet

DRILLING FLUID:

DENSITY ______ ppg

CASING SHOE DATA:

SIZE ______ inch

M. DEPTH ______ feet

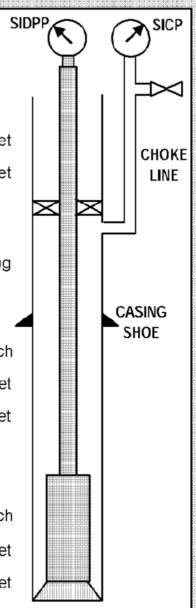
T.V. DEPTH ______ feet

HOLE DATA:

SIZE ______ inch

M. DEPTH ______ feet

T.V. DEPTH ______ feet



PUMP NO. 1 DISPL	PUMP NO. 2 DISPL
bbls / stroke	bbls / stroke

SLOW PUMP RATE DATA:	(PL) DYNAMIC PRESSURE LOSS [psi] PUMP N° 1 Through Riser	Through Choke Line	*Choke Line Friction*	PUMP N° 2 Through Riser	Through Choke Line	*Choke Line Friction*
SPM						
SPM						

TO CALCULATE STROKES / TIME AUTOMATICALLY ENTER PUMP NO. HERE ______ AND PUMP RATE HERE ______

PRE-RECORDED VOLUME DATA	LENGTH feet		CAPACITY bbls/feet		VOLUME bbls	PUMP STROKES Strokes	TIME Minutes
DRILLPIPE		x		=		VOLUME / PUMP DISPLACEMENT =	PUMP STROKES / SLOW PUMP RATE
HEVI WALL DRILL PIPE		x		=	+		
DRILL COLLARS		x		=	+		
DRILL STRING VOLUME					(D) bbls	(E) strokes	min
DC x OPEN HOLE		x		=			
DP / HWDP x OPEN HOLE		x		=	+		
OPEN HOLE VOLUME					(F) bbls	strokes	min
DP x CASING		x		= (G)	+	strokes	min
CHOKELINE		x		= (H)	+	strokes	min
TOTAL ANNULUS/CHOKELINE VOLUME					(F+G+H) = (I) bbls	strokes	min
TOTAL WELL SYSTEM VOLUME					(D+I) = (J) bbls	strokes	min
ACTIVE SURFACE VOLUME					(K) bbls	strokes	
TOTAL ACTIVE FLUID SYSTEM					(J+K) bbls	strokes	
MARINE RISER x DP		x		=	bbls	strokes	

APPENDIX
FORMS AND PROCEDURES
KILL SHEET FORMS

Transocean
Subsea BOP Vertical Well Kill Sheet (Oilfield Units)

Page 2 of 2
DATE: ____________
RIG: ____________

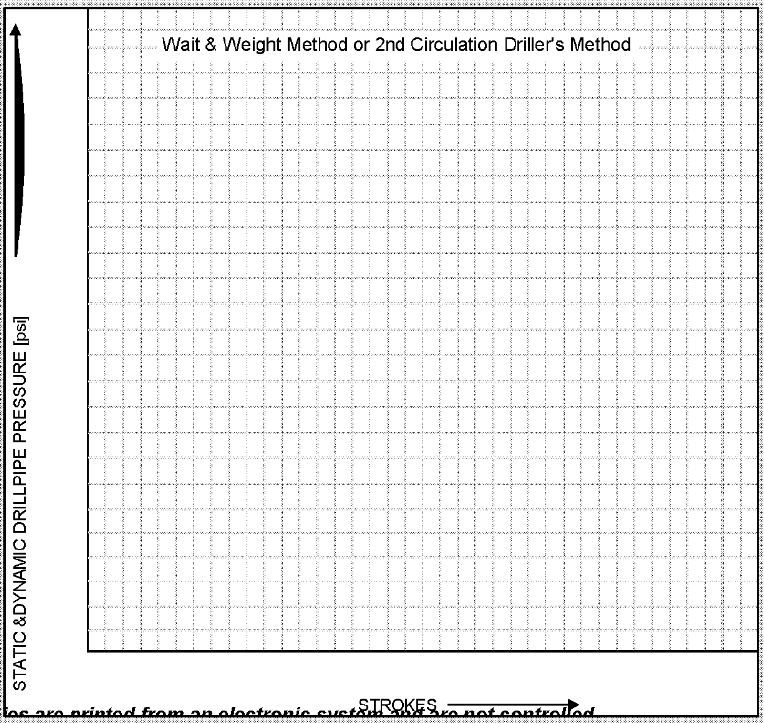
KICK DATA
SIDPP ______ psi SICP ______ psi PIT GAIN ______ barrels

KILL FLUID DENSITY KMD	CURRENT DRILLING FLUID DENSITY + SIDPP / (TVD x 0.052) + ______ / (x 0.052) = ______ ppg
INITIAL CIRC. PRESSURE ICP @ SPM	DYNAMIC PRESSURE LOSS + SIDPP + = ______ psi
FINAL CIRCULATING PRESSURE FCP @ SPM	KILL FLUID DENSITY / CURRENT DRILLING FLUID DENSITY x DYNAMIC PRESSURE LOSS ______ x = ______ psi

(L) = ICP - FCP = - = psi | (L) x 100 / (E) = ______ *x 100* = psi / 100 strokes

INITIAL DYNAMIC CASING PRESSURE AT KILL PUMP RATE	SICP - CHOKE LINE FRICTION - = ______ psi

STROKES	PRESSURE (psi)



Transocean

Subsea BOP Deviated Well Kill Sheet (Oilfield Units)

Page 1 of 3

DATE:

RIG:

THIS SHEET CAN BE PRINTED AND USED AS A BLANK OR AS A SPREADSHEET. IN WHICH CASE INPUT DATA INTO THE COLOURED CELLS ONLY

FORMATION STRENGTH DATA:

SURFACE LEAK-OFF PRESSURE FROM FORMATION STRENGTH TEST (A) psi

DRILLING FLUID DENSITY AT TEST (B) ppg

MAXIMUM ALLOWABLE DRILLING FLUID DENSITY =

(B) + (A) / SHOE T.V. DEPTH x 0.052 = (C) ppg

INITIAL MAASP =

((C) - CURR. DENS.) x SHOE T.V. DEPTH x 0.052

= psi

CURRENT DRILLING FLUID:

DENSITY ppg

SUBSEA BOP DATA:

MARINE RISER LENGTH ft

CHOKELINE LENGTH ft

DEVIATION DATA:

KOP M.D. ft

KOP T.V.D. ft

EOB M.D. ft

EOB T.V.D. ft

CASING SHOE DATA:

SIZE in

M. DEPTH ft

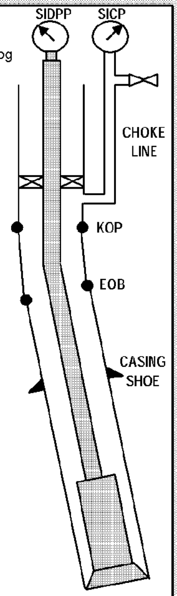
T.V. DEPTH ft

HOLE DATA:

SIZE in

M. DEPTH ft

T.V. DEPTH ft



PUMP NO. 1 DISPL	PUMP NO. 2 DISPL
bbl / stroke	bbl / stroke

SLOW PUMP RATE DATA	(PL) DYNAMIC PRESSURE LOSS [psi] PUMP N° 1 Through Riser	Through Choke Line	Choke Line Friction	PUMP N° 2 Through Riser	Through Choke Line	Choke Line Friction
SPM						
SPM						

TO CALCULATE STROKES / TIME AUTOMATICALLY ENTER PUMP NO. HERE | AND PUMP RATE HERE

PRE-RECORDED VOLUME DATA	LENGTH ft		CAPACITY bbls/ft		VOLUME bbl	PUMP STROKES stks	TIME minutes
DP - SURFACE TO KOP		x		=		(L) stks	
DP - KOP TO EOB		x		=	+	(M) stks	
DP - EOB TO BHA		x		=	+	(N1) stks	
HEVI WALL DRILL PIPE		x		=	+	(N2) stks	
DRILL COLLAR		x		=	+	(N3) stks	
DRILL STRING VOLUME					(D) bbl	stks	min
DC x OPEN HOLE		x		=			
DP / HWDP x OPEN HOLE		x		=	+		
OPEN HOLE VOLUME					(F) bbl	stks	min
DP x CASING		x		=	(G) +	stks	min
CHOKELINE		x		=	(H) +	stks	min
TOTAL ANNULUS/CHOKELINE VOLUME					(F+G+H) = (I) bbl	stks	min
TOTAL WELL SYSTEM VOLUME					(D+I) = (J) bbl	stks	min
ACTIVE SURFACE VOLUME					(K) bbl	stks	
TOTAL ACTIVE FLUID SYSTEM					(J+K) bbl	stks	
MARINE RISER x DP		x		=	bbl	stks	

APPENDIX
FORMS AND PROCEDURES
KILL SHEET FORMS

Transocean

Subsea BOP Deviated Well Kill Sheet (Oilfield Units)

Page 2 of 3

DATE: ____________

RIG: ____________

KICK DATA

SIDPP [ ] psi SICP [ ] psi PIT GAIN [ ] bbl

KILL FLUID DENSITY KMD	CURRENT DRILLING FLUID DENSITY + $\frac{\text{SIDPP}}{\text{TVD x 0.052}}$ + $\frac{\qquad}{\text{x } 0.052}$ =	____ ppg
INITIAL CIRC. PRESS. ICP @ SPM	DYNAMIC PRESSURE LOSS + SIDPP + =	____ psi
INITIAL DYNAMIC CASING PRESS AT KILL PUMP RATE	SICP - CHOKE LINE FRICTION - =	____ psi
FINAL CIRCULATING PRESSURE FCP @ SPM	$\frac{\text{KILL FLUID DENSITY}}{\text{CURRENT DRILLING FLUID DENSITY}}$ x DYNAMIC PRESSURE LOSS ____ x =	____ psi
DYNAMIC PRESSURE LOSS AT KOP (O)	PL + [(FCP - PL) x $\frac{\text{KOPMD}}{\text{TDMD}}$] = + [[-] x ____] =	____ psi
REMAINING SIDPP AT KOP (P)	SIDPP - [(KMD - OMD) x 0.052 x KOPTVD] = - [[-] x *0.052* x]	____ psi
CIRCULATING PRESS. AT KOP (KOP CP)	(O) + (P) = + =	____ psi
DYNAMIC PRESS. LOSS AT EOB (R)	PL + [(FCP-PL) x $\frac{\text{EOBMD}}{\text{TDMD}}$] = = + [[-] x ____] =	____ psi
REMAINING SIDPP AT EOB (S)	SIDPP - [(KMD - OMD) x 0.052 x EOBTVD] = - [[-] x *0.052* x]	____ psi
CIRCULATING PRESS. AT EOB (EOB CP)	(R) + (S) = + =	____ psi

(T) = ICP - KOP CP = - = psi	$\frac{\text{(T) x 100}}{\text{(L)}}$ = ____ x 100 = psi / 100 strokes
(U) = KOPCP - EOBCP = - = psi	$\frac{\text{(U) x 100}}{\text{(M)}}$ = ____ x 100 = psi / 100 strokes
(V) = EOBCP - FCP = - = psi	$\frac{\text{(V) x 100}}{\text{(N1+N2+N3)}}$ = ____ x 100 = psi / 100 strokes

APPENDIX
FORMS AND PROCEDURES
KILL SHEET FORMS

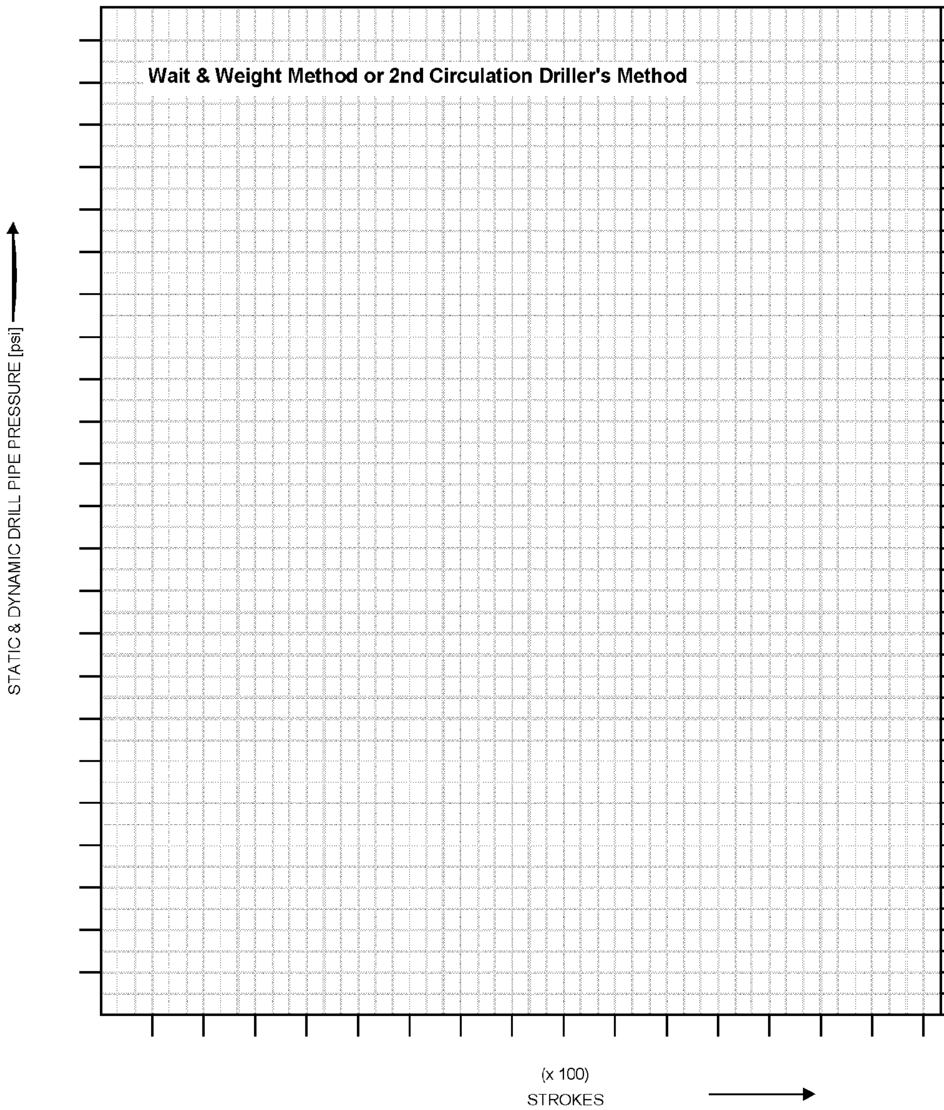
Transocean

Subsea BOP Deviated Well Kill Sheet (Oilfield Units)

Page 3 of 3

DATE: ____________

RIG: ____________



STROKES	PRESSURE (psi)

1 TRANSOCEAN STRIPPING SHEET

Pre-stripping Calculations

The attached data and calculation sheet should be completed prior to stripping operations.

Worksheet

Column A **Time:** Note the time as every operation is done.

Column B **Stand No:** Note Stand No as every operation is done.

Column C **Bit Depth:** Bit depth as pipe is being stripped.

Column D **Trip tank volume (start):** Note volume of mud in trip tank prior to stripping of given stand.

Column E **Volume bled to strip tank:** Volume bled at a single operation. If influx is left to migrate, write zero (0). When the influx is at surface, stop bleeding process, because BHP decrease at this point will lead to another influx. Then proceed with the static/dynamic volumetric process described in Section 6.3.1 or Section 6.4.

Column F **Trip tank volume (after bleed):** Note volume in trip tank once closed-end displacement volume is bled off.

Column G **Net gain:** (Column F) - (Column D)

Column H **Total gain:** Cumulative of Column G. Once volume reaches predetermined volume (W from calculation sheet), the Pchoke is increased and volume zeroed.

Column I **Pchoke:** Choke Pressure used to monitor the well pressure.

Note: When stripping procedures are completed, killing procedures should be followed.

2 STRIPPING PROCEDURES - PRE-STRIPPING CALCULATIONS

Well No: **Rig:** **Date:**

DATA

Hole Measured Depth (A) =	ft	OH Dia (G)=	ins
Bit Measured Depth (B) =	ft	OD_{dc} (H) =	ins
Mud Weight (C) =	ppg	OD_{dp} (I)=	ins
Influx Vol (D) =	bbls	ID_{dp} (J) =	ins
Influx Gradient (E) = *(use 0.1 psi/ft if unknown)*	psi/ft	Mud Gradient (K)	psi/ft
		P_{step} (L) =	psi
SICP (F) =	psi	MAASP (M) =	psi

CALCULATIONS

OH Capacity (N) =	$(G)^2/1029.4$	bbls/ft
OH: DC Capacity (O) =	$\{(G)^2 - (H)^2\}/1029.4$	bbls/ft
DP Capacity (P) =	$(J)^2/1029.4$	bbls/ft
DP Metal Displacement (Q) =	$\{(I)^2 - (J)^2\}/1029.4$	bbls/ft
Closed End Displacement (R) =	(P) + (Q)	bbls/ft
OH Influx Height (S) =	(D)/(N)	ft
Influx Height around DC's (T) =	(D)/(O)	ft
P_{saf} (U) =	{(T) - (S)} x {(K) - (E)}	psi
Volume Increment (V) =	(K)/(O)	psi/bbls
Volume increase to change P_{choke} (W) =	(L)/(V)	bbls
P_{choke} =	SICP (F) + P_{step} (L) + P_{saf} (U)	psi

3 STRIPPING PROCEDURES – WORKSHEET

A	B	C	D	E	F	G	H	I	J
Time	Std No	Bit Depth	Trip Tank Vol Start	Vol Bled to Strip Tank	Trip Tank Vol After Bled	Net Gain (F-D)	Total Gain Cumul G	*Pchoke	Comments

NOTE: *P_{choke} is kept constant until Total Gain (H) equals pre-determined volume increase (W). P_{choke} is then increased by P_{step} (L).

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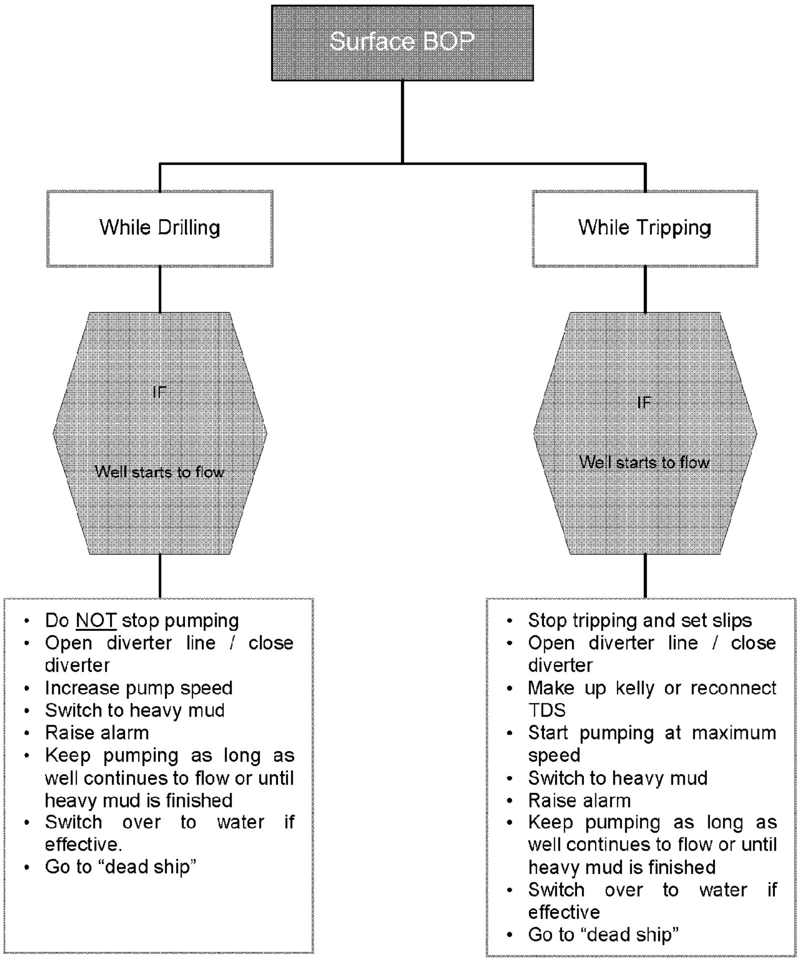
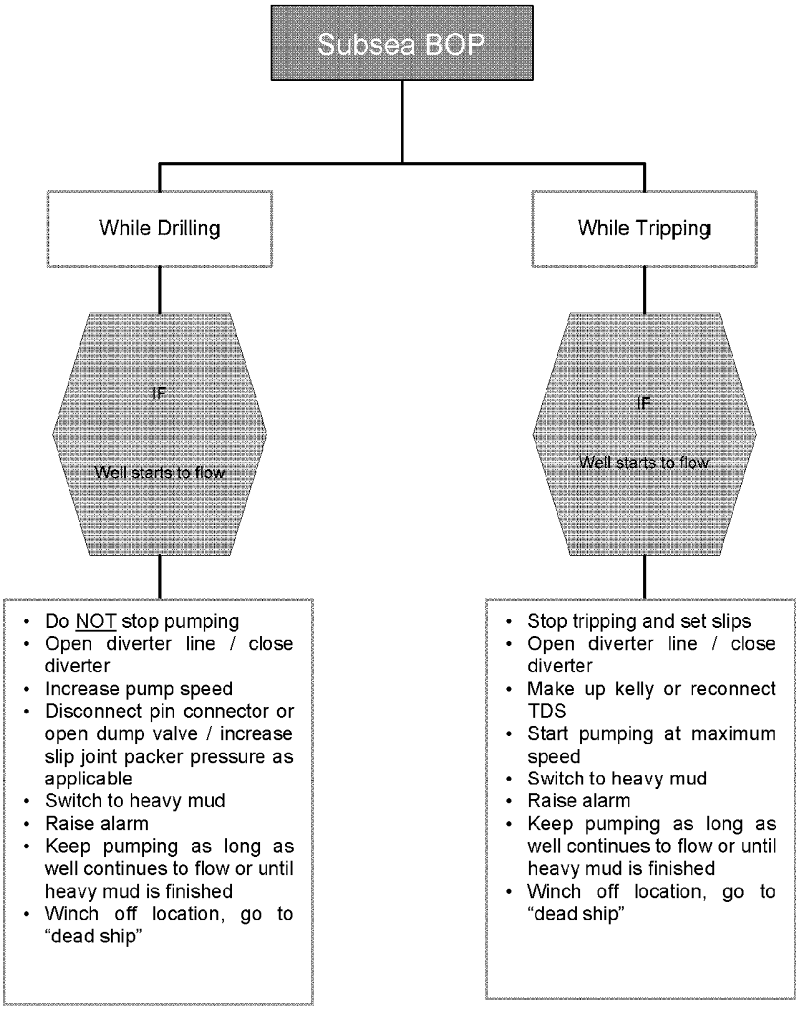
1 DIVERTING PROCEDURES (SURFACE)

TRANSOCEAN WELL CONTROL PROCEDURES
While Posted Instructions Are To Divert



2 DIVERTING PROCEDURES (SUBSEA)

TRANSOCEAN WELL CONTROL PROCEDURES
While Posted Instructions Are To Divert
(i.e. drilling top-hole section with a pin connector)



1 WELL CONTROL EVENT REPORT

Instruction for completing the report

- Record the stabilized Shut in Drill pipe pressure (SIDP) & Shut in casing pipe pressure (SICP). Include pressure build up plot
- Record the time required to obtain stabilized shut in pressures
- Record the time in which the well was shut in once the increase in flow / pit gain was observed in the report
- Do not report Pit gain as "increase in flow". As far as practically possible this volume increase should be reported. For e.g Volume gain could be a minimum value as low as 0.1 bbl.
- The Kick Intensity (KI) can be calculated as follows

  For Oil Field Units
  KI, ppg = SIDP, psi / (TVD, ft x 0.052)

  For Metric Units
  KI, Kg/l = SIDP, bar / (TVD, m x 0.0981)
  (Kg/l x 8.33 = ppg)

  For SI Units
  KI, Kg/m3 = SIDP, KPa x 102 / TVD, m
  (Kg/m3 x 0.00835 = ppg)
- If annular pressure sub is available in the BHA include the ECD in the report
- Report MAASP & Kick tolerance based on the original mud weight (Mud weight at the time of the well control event)
- Report any exemption that were in place, when the event occurred
- Type of influx is intended to be included once it is circulated out of the well
- Please include your diagnosis of the Well control event in the "Reason for event" along with any other relevant information as below
  - Kick
  - Loss / gain in that particular well section (i.e. it could be Ballooning or Supercharging)
  - Sustained casing pressure (Annulus pressure at wellheads)
  - Precautionary. Should the well shut in and circulated as a precaution

- Please report the pit gain at surface as the result of the influx being circulated out of the well bore
- Attached additional pages if required to describe the event
- Supporting documentation e.g Mud logging charts, PWD charts
- Kill sheet must be included

Figure 10.2.4.1, Well Control Event Report

Operation Event Report - Format for Well Control Event

Date		Report No	
Well Name		Report Type	**Well Control Event**
Rig Name		Operator	
Well Type		Water Depth	ft

Hole size, in	Well Depth		Bit depth	
	TVD, ft	MD, ft	TVD, ft	MD, ft

Casing size, in	Casing shoe depth		Grade	PPF	Conns	Casing pressure tested to, psi
	TVD, ft	MD, ft				

*Include prevoius casing details if the last casing is a Liner

	Main Activity e.g Drilling	Secondary Operation e.g Flow check
Well kicked while		

Shut in Drill pipe pressure		psi	Shut in Casing pressure		psi
Time allowed for pressures to stabilise		Hrs/min			
Mud Type			**Pit gain / Influx volume**		**bbls**
Original Mud weight		ppg	Leak off test / FIT		EMW, ppg
ECD @ shoe		ppg	MAASP		psi
Kill Mud weight		ppg	Kick tolerance		bbl
Expected kick zone, TVD BRT			**Kick Intensity**		**ppg**
Formation of Kick Zone					
Well Kill Method			Type of Influx		
BOP Size		in	BOP Rating		psi
Riser size (ID)		in	Barite Stock		MT
Fluids in Choke line		And	Density		ppg
Fluids in kill line		And	Density		ppg
Total Event Hours		Hrs			

Figure 10.2.4.1, Well Control Event Report (Continued)

Describe operation and actions taken until well was shut in
Reason for Event
Any Equipment Failures (Malfunctions)
Planned / Any Deviation from Well Control Policy / Existing exemptions in place
Action taken / Lesson learned

2 WELL CONTROL RECORD

Figure 10.2.4.2 Well Control Record

DESCRIBE KILL OPERATION PRESSURE, BBLS, TIMES, ETC.

TIME	STROKES	DPP	CP	PIT.VOL CHANGE BBLS	REMARKS

Figure 10.2.4.2 Well Control Record

List of PERSONNEL INVOLVED IN THIS OPERATION & THEIR RESPONSIBILITY WAS:

NAME	POSITION	RESPONSIBILITY

COPY: BUSINESS UNIT DIRECTOR OF OPERATIONS PERFORMANCE / OPERATIONS MANAGER PERFORMANCE / RIG MANAGER PERFORMANCE / WELL OPERATIONS GROUP / BUSINESS UNIT/DIVISION TRAINING CENTRE / RIG FILE

1 PERFORMANCE MONITORING AUDIT AND ASSESSMENT AUDIT

The Performance Audit and Assessment Criteria for the Well Control Manual is included in the Performance Monitoring Audit and Assessment (PMAA) Criteria Standard Manual, HQS-CMS-STD-01.

2 EQUIPMENT HARDWARE AUDITS

The Equipment Hardware Audit for the Well Control equipment is maintained by the Corporate Maintenance Group.

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APPENDIX
WELL CONTROL FORMULAE
Any Units

1 BOTTOM HOLE PRESSURE

(General case)

$P_{h(DS)} + P_{DP} - P_{Losses\ (DS)}$

$P_{h(Ann)} + P_{Ann} + P_{Losses\ (Ann)}$

(Shut In Well)

$P_{h(DS)}$ + SIDPP

$P_{h(Ann)}$ + SICP

(Circulating)

$P_{h(DS)}$ + P*DP* - $P_{Losses\ (DS)}$

$P_{h(Ann)}$ + APL

P*DP* = $P_{Losses\ (DS)}$+ APL

(Killing Well @ SCR)

$P_{Losses\ (DS)}$ + P*DP* - SCRP

$P_{h(Ann)} + P_{Ann}$ *(Surface BOP, assuming negligible APL)*

$P_{h(Ann)} + P_{Ann}$ + CLFL *(Subsea BOP, assuming negligible APL)*

2 BOYLE'S LAW

$P_1V_1 = P_2V_2,\ P_2 = \frac{P_1V_1}{V_2},\ V_2 = \frac{P_1V_1}{P_2}$

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APPENDIX

WELL CONTROL FORMULAE

OIL FIELD UNITS

1. **PRESSURE GRADIENT (psi/ft)**
   Mud Weight (ppg) x 0.052

2. **HYDROSTATIC PRESSURE (psi)**
   Mud Weight (ppg) x 0.052 x TVD (ft)

3. **FORMATION PRESSURE (psi)**
   Hydrostatic Pressure in Drillpipe (psi) + SIDPP (psi)

4. **EQUIVALENT MUD WEIGHT (ppg)**
   $$\frac{\text{Hydrostatic Pressure of Mud (psi)}}{\text{TVD (ft)} \times 0.052}$$
   or
   Pressure (psi) ÷ TVD (ft) ÷ 0.052

5. **EQUIVALENT CIRCULATING DENSITY (ppg)**
   $$\frac{\text{Annular Pressure Loss (psi)}}{\text{TVD (ft)} \times 0.052} + \text{Mud Weight (ppg)}$$
   or
   (Annular Pressure Loss (psi) ÷ TVD (ft) ÷ 0.052) + Mud Weight (ppg)

6. **KICK TOLERANCE (ppg) – simplified equation (see Section 2, Subsection 4 for full equation)**
   $$\frac{\{\text{MAASP (psi)} - [\text{Mud Weight (ppg)} \times 0.052 \times \text{Height of Influx (ft)}]\}}{\text{TVD (ft)} \times 0.052}$$

7. **MAXIMUM ALLOWABLE ANNULAR SURFACE PRESSURE (psi)**
   LOT (psi) – [(Current Mud Wt (ppg) - Mud Wt_{LOT} (ppg)) x 0.052 x TVD_{SHOE} (ft)]
   or
   (Max Allowable Mud Wt (ppg) – Current Mud Wt (ppg)) x 0.052 x TVD_{SHOE} (ft)

8. **MAXIMUM ALLOWABLE MUD WEIGHT (ppg)**
   $$\frac{\text{Leak Off Pressure (psi)}}{TVD_{SHOE}\text{ (ft)} \times 0.052} + \text{Mud } Wt_{LOT}\text{ (ppg)}$$
   or
   (Leak Off Pressure (psi) ÷ TVD_{SHOE} (ft) ÷ 0.052) + Mud Wt_{LOT} (ppg)

9. **NEW MAASP WITH KILL MUD WEIGHT (psi)**
   [Max. Allowable Mud Wt (ppg) - Kill Mud Wt (ppg)] x 0.052 x TVD_{SHOE} (ft)

10. INITIAL CIRCULATING PRESSURE (psi)

PL (psi) + SIDPP (psi)

or

SCRP (psi) + SIDPP (psi)

11. FINAL CIRCULATING PRESSURE (psi)

$$\text{PL (psi)} \times \frac{\text{Kill Mud Weight (ppg)}}{\text{Original Mud Weight (ppg)}}$$

or

$$\text{SCRP (psi)} \times \frac{\text{Kill Mud Weight (ppg)}}{\text{Original Mud Weight (ppg)}}$$

12. KILL MUD WEIGHT (ppg)

$$\frac{\text{SIDPP (psi)}}{\text{TVD (ft)} \times 0.052} + \text{Original Mud Weight (ppg)}$$

or

(SIDPP (psi) ÷ TVD (ft) ÷ 0.052) + Original Mud Weight (ppg)

13. SHUT IN CASING PRESSURE (psi)

{[Mud Gradient (psi/ft) - Influx Gradient (psi/ft)] x Influx Height (ft)} + SIDPP (psi)

14. HEIGHT OF INFLUX ALONG HOLE (ft)

$$\frac{\text{Kick Size (bbls)}}{\text{Annular Volume (bbls/ft)}}$$

15. GRADIENT OF INFLUX (psi/ft)

$$[\text{Mud Weight (ppg)} \times 0.052] - \frac{[\text{SICP (psi)} - \text{SIDPP (psi)}]}{\text{Influx TVD Height (ft)}}$$

16. PUMP OUTPUT (bbls/min)

Liner Capacity (bbls/stk) x Pump Speed (spm) x Pump Efficiency

17. ANNULAR VELOCITY (ft/min)

$$\frac{\text{Pump Output (bbls/min)}}{\text{Annular Volume (bbls/ft)}}$$

18. TRIP MARGIN/SAFETY FACTOR (ppg)

$$\frac{\text{Safety Margin (psi)}}{\text{TVD (ft)} \times 0.052} + \text{Mud Weight (ppg)}$$

or

(Safety Margin (psi) ÷ TVD (ft) ÷ 0.052) + Mud Weight (ppg)

19. NEW PUMP PRESSURE WITH NEW PUMP STROKES (psi)

$$\text{Current Pressure (psi)} \times \left(\frac{\text{New SPM}}{\text{Old SPM}}\right)^2 \text{ (approximate)}$$

20. NEW PRESSURE LOSS WITH NEW MUD WT(psi)

$$\text{Original Pressure Loss (psi)} \times \frac{\text{New Mud Wt (ppg)}}{\text{Old Mud Wt (ppg)}}$$

21. RATE OF GAS MIGRATION (ft/hr)

$$\frac{\text{Increase in Surface Pressure (psi/hr)}}{\text{Mud Weight (ppg)} \times 0.052}$$

or

Increase in Surface Pressure (psi/hr) ÷ Mud Weight (ppg) ÷ 0.052

22. VOLUME TO BLEED TO MAINTAIN BHP (bbls)

$$\frac{\text{Increase in Pressure (psi)} \times \text{Original Kick Volume (bbls)}}{\text{Formation Pressure (psi)} - \text{Increase in Pressure (psi)}}$$

23. BARITE REQUIRED TO RAISE MUD WT (ppb)

$$\frac{[\text{Kill Mud Weight (ppg)} - \text{Original Mud Weight (ppg)}] \times 1500}{35.5 - \text{Kill Mud Weight (ppg)}}$$

24. SLUG VOLUME (bbls)

$$\frac{\text{Length of Dry Pipe (ft)} \times \text{DP Cap (bbls/ft)} \times \text{Mud Wt (ppg)}}{\text{Slug Wt (ppg)} - \text{Mud Wt (ppg)}}$$

25. PIT GAIN DUE TO SLUG U-TUBING (bbls)

$$\text{Slug Vol (bbls)} \times \left(\frac{\text{Slug Wt (ppg)}}{\text{Mud Wt (ppg)}} - 1\right)$$

26. PIPE TO PULL BEFORE WELL FLOWS (ft)

$$\frac{\text{Overbalance (psi)} \times [\text{Csg Cap (bbls/ft)} - \text{DP Disp (bbls/ft)}]}{\text{Mud Weight (ppg)} \times 0.052 \times \text{DP Disp (bbls/ft)}}$$

27. PRESSURE DROP/ FT TRIPPING DRY PIPE (psi/ft)

$$\frac{\text{Mud Weight (ppg)} \times 0.052 \times \text{DP Disp (bbls/ft)}}{\text{Csg Cap (bbls/ft)} - \text{DP Disp (bbls/ft)}}$$

28. PRESSURE DROP/ FT TRIPPING WET PIPE (psi/ft)

$$\frac{\text{Mud Weight (ppg)} \times 0.052 \times [\text{DP Disp (bbls/ft)} + \text{DP Cap (bbls/ft)}]}{\text{(Annular Cap (bbls/ft))}}$$

29. DROP IN MUD LEVEL DUE TO COMPLETE POOH DRY DCs (ft)

$$\frac{\text{Length of DC (ft)} \times \text{DC Disp (bbls/ft)}}{\text{Casing Capacity (bbls/ft)}}$$

APPENDIX
WELL CONTROL FORMULAE
Metric Units

1. **PRESSURE GRADIENT (bar/m)**
   Mud Weight (kg/l) x 0.0981

2. **HYDROSTATIC PRESSURE (bar)**
   Mud Weight (kg/l) x TVD (m) x 0.0981

3. **FORMATION PRESSURE (bar)**
   Hydrostatic Pressure in Drillpipe (bar) + SIDPP (bar)

4. **EQUIVALENT MUD WEIGHT (kg/l)**
   $$\frac{\text{Pressure (bar)}}{\text{TVD (m)} \times 0.0981}$$

5. **EQUIVALENT CIRCULATING DENSITY (kg/l)**
   $$\text{Mud Weight (kg/l)} + \frac{\text{Annular Pressure Loss (bar)}}{\text{TVD (m)} \times 0.0981}$$

6. **KICK TOLERANCE (kg/l) (simplified calculation, see Section 2, Subsection 4 for full calculation)**
   $$\frac{\{\text{MAASP (bar)} - [\text{Mud Weight (kg/l)} \times \text{Height of Influx (m)} \times 0.0981\}}{\text{TVD (m)} \times 0.0981}$$

7. **MAXIMUM ALLOWABLE ANNULAR SURFACE PRESSURE (bar)**
   LOT (bar) - {[Mud Wt (kg/l) - Mud Wt_{LOT} (kg/l)] x 0.0981 x TVD_{SHOE} (m)}
   or
   Max Allowable Mud Wt (kg/l) – Mud Wt (kg/l)) x 0.0981 x TVD_{SHOE} (m)

8. **MAXIMUM ALLOWABLE MUD WEIGHT (kg/l)**
   $$\text{Mud Weight (kg/l)} + \frac{\text{Leak Off Pressure (bar)}}{TVD_{SHOE}\text{ (m)} \times 0.0981}$$

9. **NEW MAASP WITH KILL MUD WEIGHT (bar)**
   [Max Allowable Mud Wt (kg/l) - Kill Mud Wt (kg/l)] x 0.0981 x TVD_{SHOE} (m)

10. **INITIAL CIRCULATING PRESSURE (bar)**
    PL (bar) + SIDPP (bar)
    or
    SCRP (bar) + SIDPP (bar)

11. FINAL CIRCULATING PRESSURE (bar)

$$\text{PL (bar)} \times \frac{\text{Kill Mud Weight (kg/l)}}{\text{Original Mud Weight (kg/l)}}$$

or

$$\text{SCRP (bar)} \times \frac{\text{Kill Mud Weight (kg/l)}}{\text{Original Mud Weight (kg/l)}}$$

12. KILL MUD WEIGHT (kg/l)

$$\frac{\text{SIDPP (bar)}}{\text{TVD (m)} \times 0.0981} + \text{Original Mud Weight (kg/l)}$$

13. SHUT IN CASING PRESSURE (bar)

{[Mud Gradient (bar/m) - Influx Gradient (bar/m)] x Influx Height (m)} + SIDPP (bar)

14. HEIGHT OF INFLUX ALONG HOLE (m)

$$\frac{\text{Kick Size (litres)}}{\text{Annular Volume (litres/m)}}$$

15. GRADIENT OF INFLUX (bar/m)

$$\text{Mud Weight (kg/l)} \times 0.0981 - \frac{[\text{SICP (bar)} - \text{SIDPP (bar)}]}{\text{Influx TVD Height (m)}}$$

16. PUMP OUTPUT (litre/min)

Liner Capacity (litres/stk) x Pump Speed (spm) x Pump Efficiency

17. ANNULAR VELOCITY (m/min)

$$\frac{\text{Pump Output (litres/min)}}{\text{Annular Volume (litres/m)}}$$

18. TRIP MARGIN/SAFETY FACTOR (kg/l)

$$\text{Mud Weight (kg/l)} + \frac{\text{Safety Margin (bar)}}{\text{TVD (m)} \times 0.0981}$$

19. NEW PUMP PRESSURE WITH NEW PUMP STROKES (bar)

$$\text{Current Pressure (bar)} \times \left(\frac{\text{New SPM}}{\text{Old SPM}}\right)^2 \text{ (approximate)}$$

20. NEW PRESSURE LOSS WITH NEW MUD WT (bar)

$$\text{Original Pressure Loss (bar)} \times \frac{\text{New Mud Wt (kg/l)}}{\text{Old Mud Wt (kg/l)}}$$

APPENDIX
WELL CONTROL FORMULAE
Metric Units

21. RATE OF GAS MIGRATION (m/hr)

$$\frac{\text{Increase in Surface Pressure (bar/hr)}}{\text{Mud Weight (kg/l)} \times 0.0981}$$

22. VOLUME TO BLEED TO MAINTAIN BHP (litres)

$$\frac{\text{Increase in Pressure (bar)} \times \text{Original Kick Volume (litres)}}{\text{Formation Pressure (bar)} - \text{Increase in Pressure (bar)}}$$

23. BARITE REQUIRED TO RAISE MUD WT (kg/l)

$$\frac{[\text{Kill Mud Weight (kg/l)} - \text{Original Mud Weight (kg/l)}] \times 4.2}{4.2 - \text{Kill Mud Weight (kg/l)}}$$

24. SLUG VOLUME (litres)

$$\frac{\text{Length of Dry Pipe (m)} \times \text{DP Cap (l/m)} \times \text{Mud Weight (kg/l)}}{\text{Slug Wt (kg/l)} - \text{Mud Wt (kg/l)}}$$

25. PIT GAIN DUE TO SLUG U-TUBING (litres)

$$\text{Slug Volume (l)} \times \left(\frac{\text{Slug Wt (kg/l)}}{\text{(Mud Wt (kg/l)}} - 1\right)$$

26. PIPE TO PULL BEFORE WELL FLOWS (m)

$$\frac{\text{Overbalance (bar)} \times [\text{Csg Cap (l/m)} - \text{DP Disp (l/m)}]}{\text{Mud Weight (kg/l)} \times 0.0981 \times \text{DP Disp (l/m)}}$$

27. PRESSURE DROP/M TRIPPING DRY PIPE (bar/m)

$$\frac{\text{Mud Weight (kg/l)} \times 0.0981 \times \text{DP Disp (l/m)}}{[\text{Csg Cap (l/m)} - \text{DP Disp (l/m)}]}$$

28. PRESSURE DROP/M TRIPPING WET PIPE (bar/m)

$$\frac{\text{Mud Weight (kg/l)} \times 0.0981 \times [\text{DP Disp (l/m)} + \text{DP Cap (l/m)}]}{\text{Annular Cap (l/m)}}$$

29. DROP IN MUD LEVEL DUE TO COMPLETE POOH WITH DCs [DRY] (m)

$$\frac{\text{Length of DC (m)} \times \text{DC Disp (l/m)}}{\text{Casing Capacity (l/m)}}$$

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APPENDIX

WELL CONTROL FORMULAE

SI Units

1. **PRESSURE GRADIENT (kPa/m)**

$$\frac{\text{Mud Weight (kg/m}^3\text{)}}{102}$$

2. **HYDROSTATIC PRESSURE (kPa)**

$$\frac{\text{Mud Weight (kg/m}^3\text{) x TVD (m)}}{102}$$

3. **FORMATION PRESSURE (kPa)**

Hydrostatic Pressure in Drillpipe (kPa) + SIDPP (kPa)

4. **EQUIVALENT MUD WEIGHT (kg/m3)**

$$\frac{\text{Pressure (kPa) x 102}}{\text{TVD (m)}}$$

5. **EQUIVALENT CIRCULATING DENSITY (kg/m3)**

$$\text{Mud Weight (kg/m}^3\text{)} + \frac{\text{Annular Pressure Loss (kPa) x 102}}{\text{TVD (m)}}$$

6. **KICK TOLERANCE (kg/m3) (simplified equation, see Section 2, Subsection 4 for full calculation)**

$$\frac{\{\text{MAASP (kPa) - [Mud Wt (kg/m}^3\text{) x Height of Influx (m)]} \div 102)\} \text{ x 102}}{\text{TVD (m)}}$$

7. **MAXIMUM ALLOWABLE ANNULAR SURFACE PRESSURE (kPa)**

$$\text{LOT (kPa)} - \frac{[\text{Mud Wt}_{LOT}\text{ (kg/m}^3\text{) - Mud Wt (kg/m}^3\text{)] x TVD}_{SHOE}\text{ (m)}}{102}$$

or

$$\frac{\text{(Max Allowable Mud Wt (kg/m}^3\text{) – Mud Wt (kg/m}^3\text{)) x TVD}_{SHOE}\text{ (m)}}{102}$$

8. **MAXIMUM ALLOWABLE MUD WEIGHT (kg/m3)**

$$\text{Mud Weight (kg/m}^3\text{)} + \frac{\text{Leak Off Pressure (kPa) x 102}}{\text{TVD}_{SHOE}\text{ (m)}}$$

9. **NEW MAASP WITH KILL MUD WEIGHT (kPa)**

$$\frac{\text{[Max Allow Mud Wt (kg/m}^3\text{) - Kill Mud Wt (kg/m}^3\text{)] x TVD}_{SHOE}\text{ (m)}}{102}$$

APPENDIX
WELL CONTROL FORMULAE
SI Units

10. INITIAL CIRCULATING PRESSURE (kPa)

PL (kPa) + SIDPP (kPa)

or

SCRP (kPa) + SIDPP (kPa)

11. FINAL CIRCULATING PRESSURE (kPa)

$$\text{PL (kPa)} \times \frac{\text{Kill Mud Weight (kg/m}^3\text{)}}{\text{Original Mud Weight (kg/m}^3\text{)}}$$

or

$$\text{SCRP (kPa)} \times \frac{\text{Kill Mud Weight (kg/m}^3\text{)}}{\text{Original Mud Weight (kg/m}^3\text{)}}$$

12. KILL MUD WEIGHT (kg/m3)

$$\frac{\text{SIDPP (kPa)} \times 102}{\text{TVD (m)}} + \text{Original Mud Weight (kg/m}^3\text{)}$$

13. SHUT IN CASING PRESSURE (kPa)

{[Mud Gradient (kPa/m) - Influx Gradient (kPa/m)] x Influx Height (m)} + SIDPP (kPa)

14. HEIGHT OF INFLUX ALONG HOLE (m)

$$\frac{\text{Kick Size (m}^3\text{)}}{\text{Annular Volume (m}^3\text{/m)}}$$

15. GRADIENT OF INFLUX (kPa/m)

$$\left[\frac{\text{Mud Weight (kg/m}^3\text{)}}{102}\right] - \left[\frac{\text{SICP (kPa)} - \text{SIDPP (kPa)}}{\text{Influx TVD Height (m)}}\right]$$

16. PUMP OUTPUT (m3/min)

Liner Capacity (m^3/stk) x Pump Speed (spm) x Pump Efficiency

17. ANNULAR VELOCITY (m/min)

$$\frac{\text{Pump Output (m}^3\text{/min)}}{\text{Annular Volume (m}^3\text{/m)}}$$

18. TRIP MARGIN/SAFETY FACTOR (kg/m3)

$$\text{Mud Weight (kg/m}^3\text{)} + \frac{\text{Safety Margin (kPa)} \times 102}{\text{TVD (m)}}$$

19. NEW PUMP PRESSURE WITH NEW PUMP STROKES (kPa)

$$\text{Current Pressure (kPa)} \times \left(\frac{\text{New SPM}}{\text{Old SPM}}\right)^2 \text{ (approximate)}$$

20. NEW PRESSURE LOSS WITH NEW MUD WT (kPa)

$$\text{Original Pressure Loss (kPa)} \times \frac{\text{New Mud Wt (kg/m}^3\text{)}}{\text{Old Mud Wt (kg/m}^3\text{)}}$$

21. RATE OF GAS MIGRATION (m/hr)

$$\frac{\text{Increase in Surface Pressure (kPa/hr)} \times 102}{\text{Mud Weight (kg/m}^3\text{)}}$$

22. VOLUME TO BLEED TO MAINTAIN BHP (m3)

$$\frac{\text{Increase in Pressure (kPa)} \times \text{Original Kick Volume (m}^3\text{)}}{\text{Formation Pressure (kPa)} - \text{Increase in Pressure (kPa)}}$$

23. BARITE REQUIRED TO RAISE MUD WT (kg/m3)

$$\frac{[\text{Kill Mud Weight (kg/m}^3\text{)} - \text{Original Mud Weight (kg/m}^3\text{)}] \times 4200}{4200 - \text{Kill Mud Weight (kg/m}^3\text{)}}$$

24. SLUG VOLUME (m3)

$$\frac{\text{Length of Dry Pipe (m)} \times \text{DP Cap (m3/m)} \times \text{Mud Wt (kg/m}^3\text{)}}{[\text{Slug Wt (kg/m}^3\text{)} - \text{Mud Wt (kg/m3)}]}$$

25. PIT GAIN DUE TO SLUG (m3)

$$\text{Slug Volume (m}^3\text{)} \times \left(\frac{\text{Slug Wt (kg/m}^3\text{)}}{\text{(Mud Wt (kg/m}^3\text{)}} - 1 \right)$$

26. PIPE TO PULL BEFORE WELL FLOWS (m)

$$\frac{\text{Overbalance (kPa)} \times [\text{Csg Cap (m}^3\text{/m)} - \text{DP Disp (m}^3\text{/m)}] \times 102}{\text{Mud Weight (kg/m}^3\text{)} \times \text{DP Disp (m}^3\text{/m)}}$$

27. PRESSURE DROP/FT TRIPPING DRY PIPE (kPa/m)

$$\frac{\text{Mud Weight (kg/m}^3\text{)} \times \text{DP Disp (m}^3\text{/m)}}{[\text{Csg Cap (m}^3\text{/m)} - \text{DP Disp (m}^3\text{/m)}] \times 102}$$

28. PRESSURE DROP/FT TRIPPING WET PIPE (kPa/m)

$$\frac{\text{Mud Weight (kg/m}^3\text{)} \times [\text{DP Disp (m}^3\text{/m)} + \text{DP Cap (m}^3\text{/m)}]}{\text{Annular Cap (m}^3\text{/m)} \times 102}$$

29. DROP IN MUD LEVEL DUE TO COMLETE POOH WITH DCs [DRY] (m)

$$\frac{\text{Length of DC (m)} \times \text{DC Disp (m}^3\text{/m)}}{\text{Casing Cap (m}^3\text{/m)}}$$

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APPENDIX
CONVERSION FACTORS
Conversions

MULTIPLY	BY	TO GET
Depth		
Feet	0.3048	Meters
Meters	3.2808	Feet
Volume		
Gallon (US)	0.003785 3.785	Cubic Meters Litres
Barrel (US)	0.15897 158.97	Cubic Meters Litres
Cubic Meters Litres	6.2905 0.0062905	Barrel (US)
Cubic Meters Litres	264.2 0.2642	Gallon (US)
Pressure		
Psi Psi	6.895 0.06895	Kilo Pascals (kPa) Bar
KPa	0.14503 0.01	Psi Bar
Kg/cm^2 Kg/cm^2	98.1 14.223	Kilo Pascals (kPa) Psi
Bar Bar	100 14.5	Kilo Pascals (kPa) PsI
Mud Weight		
Kg/l	8.33	PPG
PPG	119.8	Kg/m^3
PPG	0.12	Kg/l
Kg/m^3	0.00835	PPG
Pressure Gradient		
Psi/ft Psi/ft	22.62 0.2262	kPa/m Bar/metre
kPa/m kPa/m	0.04421 0.01	psi/ft Bar/metre

APPENDIX
CONVERSION FACTORS
Conversions

MULTIPLY	BY	TO GET
Mud Weight to Pressure Gradient		
PPG	0.052	psi/ft
Kg/l	0.433	psi/ft
Kg/l	0.0981	Bar/metre
Lb/ft^3	0.006944	psi/ft
Kg/m^3	0.000434	psi/ft
Kg/m^3	0.00982 *	kPa/m
Flow Rate		
Gallons/min	0.003785 3.785	m^3/min litre/min
Barrels/min	0.159 159	m^3/min litre/min
Cubic meters/min Litres/min	6.2905 0.0062905	bbls/min bbls/min
Cubic meters/min Litres/min	264.2 0.2642	gals/min gals/min
Annular Velocity		
Ft/min	0.3048	m/min
m/min	3.2808	ft/min
Force		
Pounds Force	0.445	Decanewtons
DecaNewtons	2.2472	Pounds Force
Mass		
Pounds	0.454	Kilograms
Kilograms	2.2026	Pounds
Tons (long 2240 lbs)	1017	Kilograms
Tons (short 2000 lbs)	908.04	Kilograms
Tons (metric)	1000	Kilograms
Tons (metric)	2202.6	Pounds

MULTIPLY	BY	TO GET
Pipe Weights		
Lb/ft	1.49	kg/m
Kg/m	0.671	lb/ft

* **Note:** the 0.00982 factor used above to convert from mud weight (in Kg/m^3) to pressure gradient (in KPa/m) is equivalent to (1 ÷ 102) used throughout the Well Control Manual.

BUOYANCY FACTOR: 1 – (FLUID DENSITY ÷ STEEL DENSITY)
Steel: 7.85 kg/m^3, 489.58 lbs/ft^3, 3.412 psi/ft

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APPENDIX

SEISMIC EVALUATION FOR SHALLOW GAS SURVEY

The following is a quick summary reminder of things to check.

1 OPTIMIZE PRELIMINARY SHALLOW GAS INVESTIGATION

- Seismic surveys
- Soil sampling
- Pilot holes (pre-spud)

2 AVOID SHALLOW GAS WHERE POSSIBLE

- Reposition drilling location
- Re-arrange casing schemes and use BOP's
- Apply strict shallow gas procedures

3 REDUCE RISK TO RIG IN CASE OF SHALLOW GAS

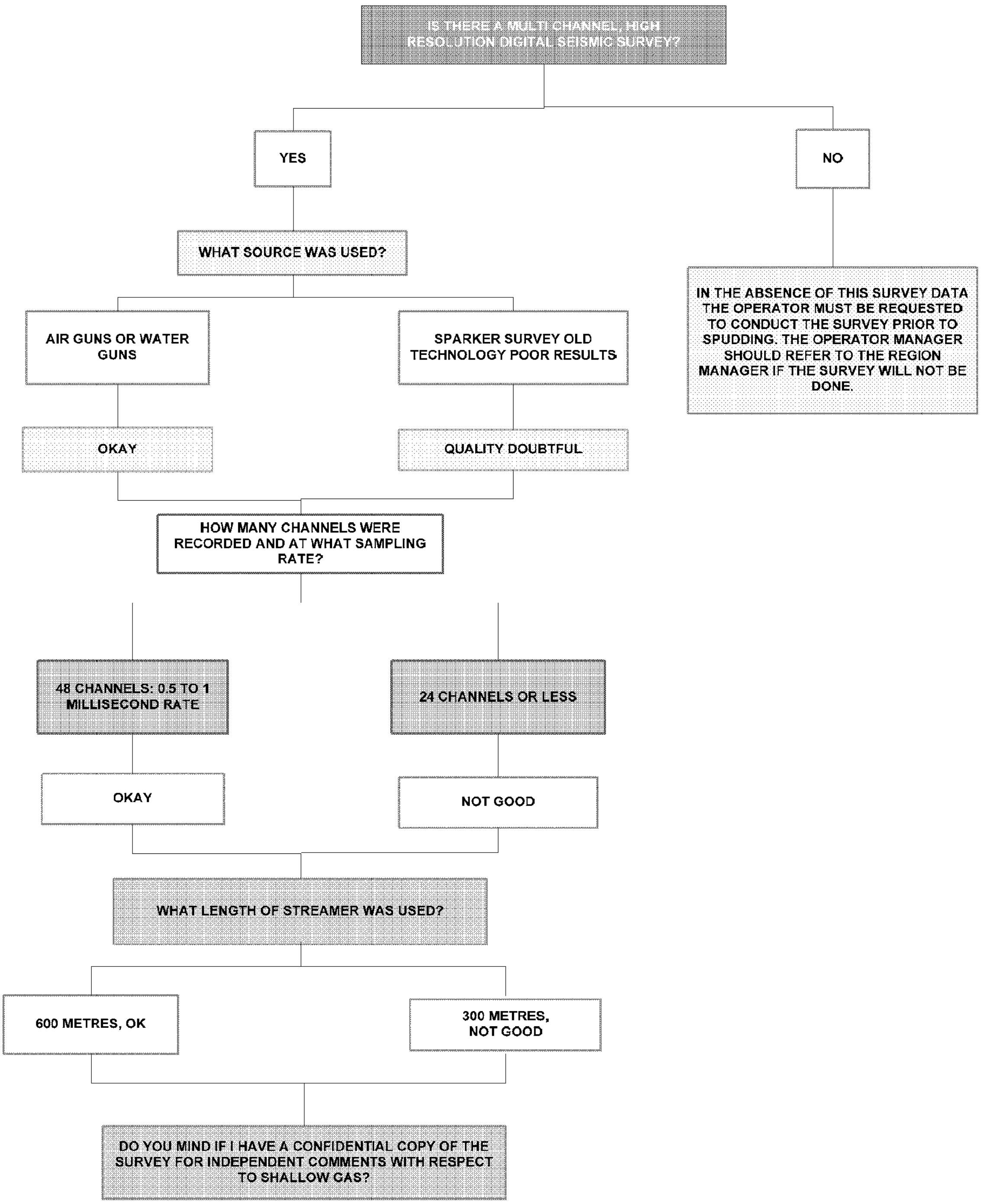
- Divert subsea
- Employ riserless drilling
- Drill small diameter pilot hole

Some of the seismic survey high resolution techniques available are not reliable or suitable for shallow gas evaluation. The following flow chart will help you evaluate whether the survey has been conducted satisfactorily.

APPENDIX

SEISMIC EVALUATION FOR SHALLOW GAS SURVEY

Figure 10.6.1: Transocean Decision Tree for Shallow Gas



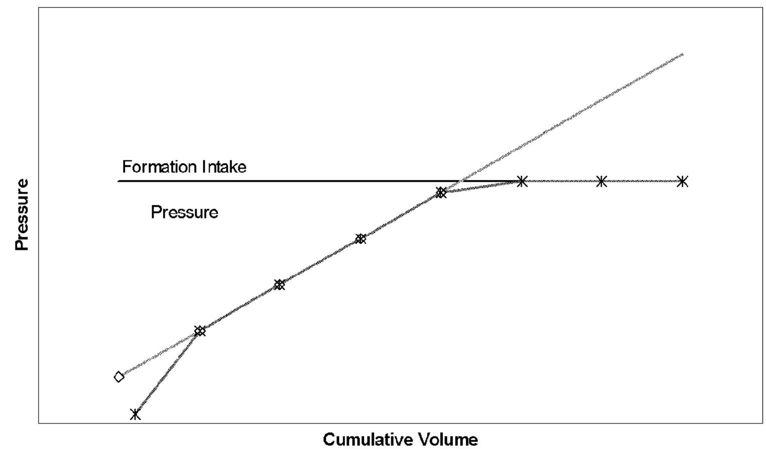
1 LOT PROCEDURE

- Drill out float collar, shoe, rathole and 10-15 feet (3-5 m) of new hole.
- Circulate and condition hole until the mud weight is uniform throughout.
- Pull bit inside casing shoe.
- Line up a high pressure, low volume pump such as a cement pump. Rig pumps are not suitable for performing leak-off tests.
- Close BOP (hang-off string on floating units). Where practicable, open annulus between last casing and previous casing strings to avoid pressure build-up.
- Circulate down the drillpipe, up the annulus and through the choke to confirm the correct line up and to flush air from the system. Close the valve on the drill pipe and pressure test the surface lines.
- Pump down the drillpipe or the annulus (it is preferable to pump down the string since the effects of mud gellation and drilled solids will be less) in either of the following ways:
  - 0.25-0.5 bbl (0.040-0.080 m^3) stages with two minute stops between each stage to allow the pressure to stabilize. Repeat pumping the selected increment, plotting the stabilized pressures until the trend of the final pumping pressure curve deviates from that of the final static pressure curve. Plot final pump pressure and final static pressure versus cumulative pumped volume on the same graph.
  - Continuously at 0.25-0.5 bbl (0.040-0.080 m3) per minute, plotting the pressure versus cumulative volume pumped every 0.25 bbls (0.040 m3).
- Monitor the final static pressure for 5-10 minutes.
- Bleed off the pressure by opening the return line back to the displacement tank and record the volume of fluid returned.

The object of the above test is not to fracture the formation, but rather to identify the formation intake pressure. This intake pressure is identified as that point where a deviation occurs between the trends of the final pump pressure curve and the static pressure curve (see Figure 10.7.1). Once the formation intake pressure has been reached, further pumping should be avoided.

If pumping is continued a fracture could occur, characterized by a sharp drop in pressure. Once formation breakdown has been initiated any further pumping will cause loss of fluid at a lower pressure referred to as the fracture propagation pressure.

Figure 10.7.1, Consolidated Formation LOT

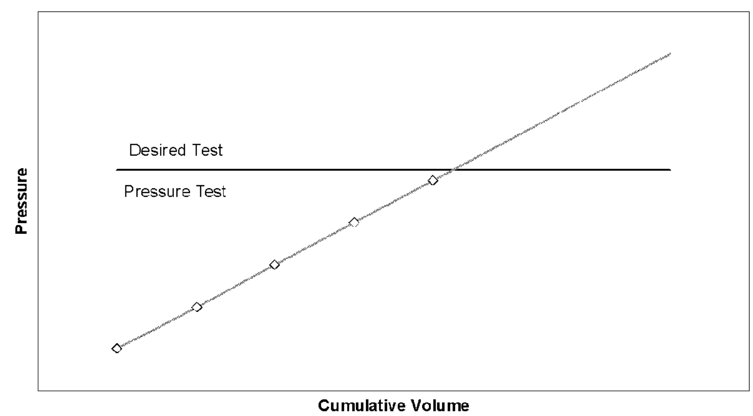


2 FIT PROCEDURE

In consolidated hard rock areas a Formation Integrity Test, FIT (also known as formation limit or shoe integrity test) should be performed instead of a leak-off test. If the leak-off test is carried out a fracture may be propagated causing a reduction in wellbore integrity. For such areas, the formation of interest should be tested to the desired test pressure for the well program. Pumping should be stopped when the predicted fracture pressure is reached (see Figure 10.7.2).

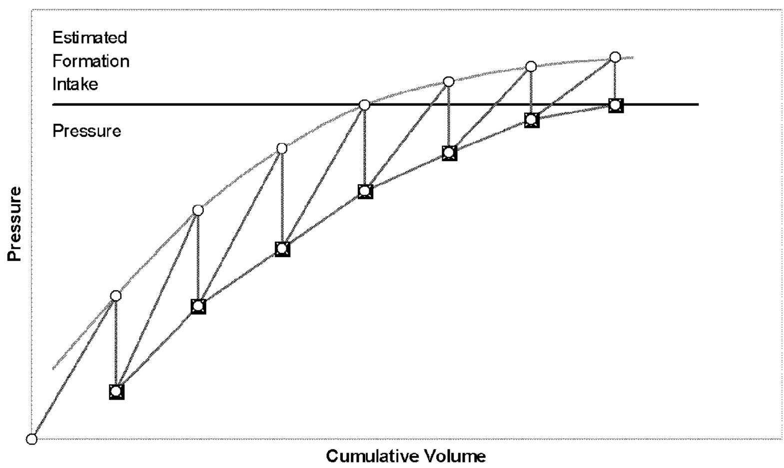
A FIT may also be performed where there is a sufficiently large kick tolerance for the subsequent section without having to take pressures near to leak-off.

Figure 10.7.2, Consolidated Formation FIT



In unconsolidated formation, the final pumping pressure will always be higher than the final static pressure. Intake pressure can only be approximated. Generally the information is adequate since the main purpose of the test is to verify the competency of the cement bond around the shoe (see Figure 10.7.3).

Figure 10.7.3, Unconsolidated Formation LOT



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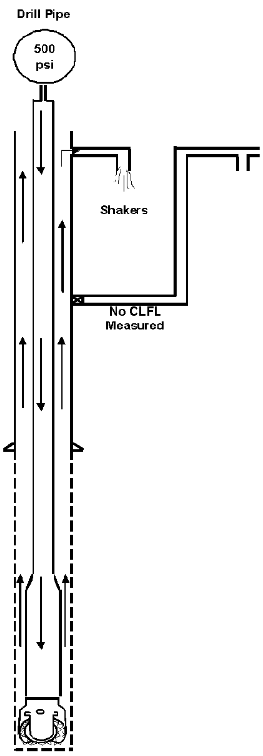
1 PRESSURE LOSSES IN SUBSEA KILL OPERATIONS

In subsea situations, a pressure loss exists when circulating through the choke due to the friction losses in the extended choke line from the BOP to surface. This pressure loss is not present when the SCRP is measured by circulating up the marine riser (see Figure 10.8.1).

Figure 10.8.1 Conventional SCRP Flow Path



If the normal method of bringing a pump to kill speed is followed (i.e. choke manifold pressure maintained equal to SICP until kill rate is achieved), BHP must be increased by an amount equal to CLFL. This excess pressure may result in lost circulation problems during the kill operations.

Since CLFL increases and fracture gradients generally decrease with increased water depth, correct handling of the CLFL becomes more critical as water depth increases. Beyond approximately 500 ft (150 m) water depths, CLFL should always be considered when planning well control operations.

2 PROCEDURES FOR RECORDING CLFL

There are four recognized methods of recording choke line friction losses at Slow Circulating Rates of 1-5 bbls/ min (0.16-0.8 m^3/min).

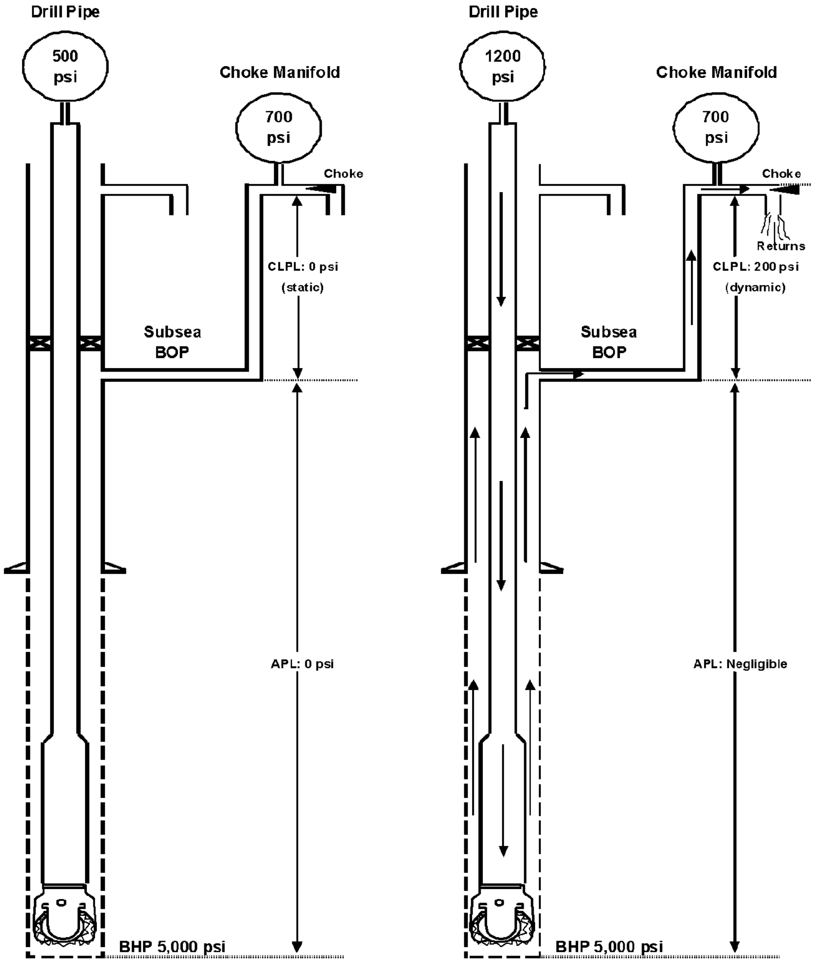
- Take the difference between the drillpipe pressure required to circulate the well through a full open choke with the BOP closed and the drillpipe pressure required to circulate the well through the marine riser with the BOP open.
- Circulate the well through a full open choke with the BOP closed and recording the pressure on the (static) kill line. The kill line pressure will reflect the choke line pressure loss.
- Circulate down the choke line and up the marine riser with the BOP open. The pressure required for circulation is a direct reflection of the choke line pressure loss.
- Circulate down the kill line taking returns through a full open choke with the wellbore and riser isolated by closing the BOP's. Pressure observed is double the choke line pressure loss.

The pressure readings provided by the choke manifold pressure sensor, rather than the pump pressure gauge, should be recorded since the effect of the pressure losses between the pump and the choke manifold are eliminated.

3 BRINGING PUMP UP TO KILL RATE SPEED (NON INSTRUMENTED BOP)

To accomplish constant BHP, a method must be used to keep total applied casing pressures relatively constant while bringing the mud pump to kill rate. If CLFL is not accounted for, casing pressure varies from SICP at pump start-up to (SICP + CLFL) with the pump at kill rate. This results in BHP increasing by an amount equal to CLFL, as shown in Figures 10.8.2 and 10.8.3.

Figure 10.8.2 and Figure 10.8.3



P_f = 5,000 psi
P_m= 4,300 psi (in annulus)
Pump off (kick shut-in)

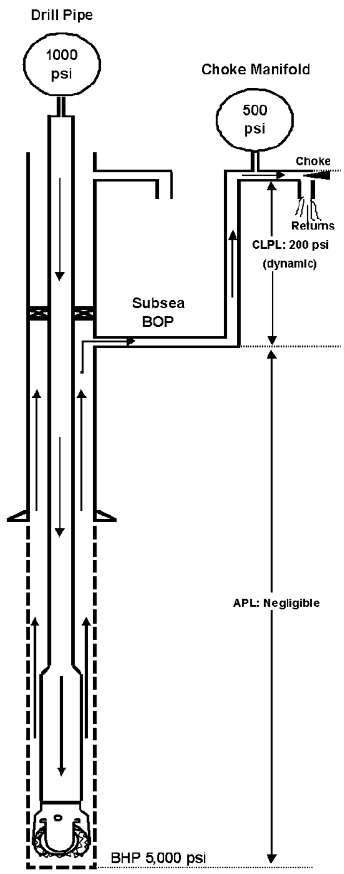
P_f = 5,000 psi
P_m= 4,300 psi (in annulus)
Pump off at kill rate holding constant choke manifold pressure
Change in BHP = 200 psi increase

To eliminate this problem, two methods exist.

A. METHOD 1 - USE KNOWN CLFL

By reducing choke pressure by an amount equal to a known CLFL, the effect of the CLFL is negated. This is accomplished by reducing the original SICP by the amount of CLFL while bringing the pump to speed (see Figure 10.8.4).

Figure 10.8.4



P_f = 5,000 psi
P_m= 4,300 psi (in annulus)
Pump off at kill rate holding constant
choke manifold pressure
Change in BHP = 0 psi increase

Reduced Choke Pressure

= SICP - CLFL

= 700 - 200 = 500 psi

A pressure chart must be created for bringing the well up to kill rate. The pressure vs. stroke relationship is not a straight line effect and the following relationship should be used:

- 4 identical pressure drops relate to 1/2, 3/4, 7/8 and full kill rate speed.

Using the example above with a kill rate speed of 50spm:

- 4 equal pressure drops = $\frac{CLFL}{4} = \frac{200}{4}$ = 50 psi steps

Corresponding pump rates:

- 1/2 x 50 = 25 spm
- 3/4 x 50 = 38 spm
- 7/8 x 50 = 44 spm
- 1 x 50 = 50 spm

This gives the following schedule:

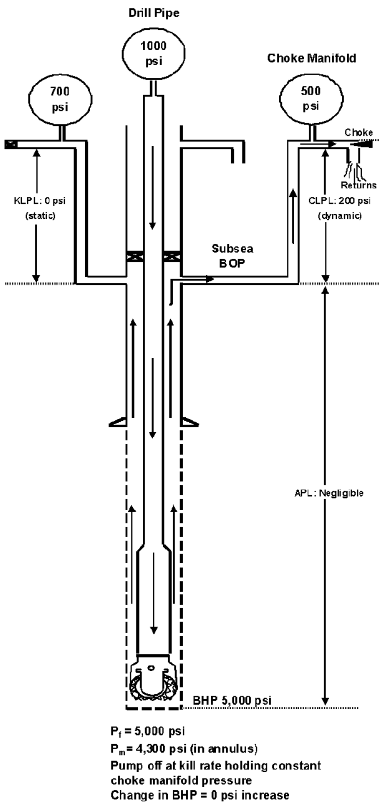
SPM	Pressure (psi)
0	700 (SICP)
25	650
38	600
44	550
50	500 (SICP-CLFL)

Once kill rate has been reached, the choke operator switches over to the drillpipe gauge and follows the drillpipe pressure graph in the usual way.

B. METHOD 2 - USE KILL LINE FOR PRESSURE MONITORING

If it is possible to use the kill line (shut off down-stream of the gauge outlet to prevent flow) to provide a pressure reading at a point upstream of any CLFL, then the kill line gauge is kept constant while bringing the pump to speed eliminating the effect of CLFL (see Figure 10.8.5).

Figure 10.8.5



The advantages of this method include:

- The gauge reading choke manifold pressure will show a decrease after pump is up to speed. The amount of this decrease is equal to the CLFL.
- No pre-calculated or pre-measured CLFL information is required.
- The kill line gauge can be subsequently used like the choke manifold pressure gauge on a surface stack for the purposes of altering pump rates or problem analysis.

NOTE: If the second method of handling the CLFL situation is preferred, it would be advisable to rig a remote kill line pressure gauge which could be seen by the choke operator.

It is extremely important to note that regardless of which method is used, they both accomplish the goal of maintaining constant BHP. This is done without the need to alter any calculations on the kill sheet. Thus ICP and FCP, which are read on the drillpipe gauge, are unaffected by CLFL. CLFL is recorded on the Kill Sheet for convenience only.

It should be noted that it will only be possible to use the above recommended methods when SICP is greater than CLFL. If this is not true, it will be unavoidable to apply excess pressure to the bottom of the hole using standard well control procedures. Also, as kill mud comes up the annulus, total casing pressure needed to maintain constant BHP will eventually drop below CLFL. After this point, drillpipe pressure will exceed planned FCP in spite of having the choke wide open.

These situations can be mitigated by use of unusually slow pumping rates or by taking returns up choke and kill lines simultaneously.

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APPENDIX

ANNULAR PRESSURE LOSS (APL) CALCULATION SHEET

The annular pressure loss (APL) is calculated with the following equation:

APL = SCRP - DSPL - SPL - BPL

Where:
APL = annular pressure loss.

SCRP = slow circulating rate pressure (measured).

SPL = surface pressure loss (measured).

BPL = bit and nozzle pressure loss (calculated).

DSPL = drillstring pressure loss (calculated).

The following example uses oilfield units:

1 OBTAIN THE DIMENSIONAL PARAMETERS REQUIRED:

Drill pipe ID	d_{dp}	(inches)
Drill pipe length	L_{dp}	(feet)
Drill collar ID	d_{dc}	(inches)
Drill collar length	L_{dc}	(feet)
Kill mud plastic viscosity	PV	(centipoise)
Kill mud yield point	YP	($lb/100ft^2$)
Kill mud weight	KMW	(ppg)
Depth of bit	TD	(feet)
Measured SCRP @ TD	$SCRP_{TD}$	(psi)
Measured SPL	SPL	(psi)
Flowrate	Q	(gpm)
Total flow area of bit	A	(in^2)

2 CALCULATE THE AVERAGE FLUID VELOCITY (FT/SEC):

Drill collars: $V_{dc} = GPM \div (2.448 \times d_{dc}^2)$

Drill pipe: $V_{dp} = GPM \div (2.448 \times d_{dp}^2)$

3 CALCULATE THE FRICTIONAL PRESSURE LOSSES (PSI) IN THE DRILLSTRING:

Drill collars: $PL_{dc} = \frac{(PV \times V_{dc} \times L_{dc})}{(1500 \times d_{dc}^2)} + \frac{(YP \times L_{dc})}{(225 \times d_{dc})}$

Drill pipe: $PL_{dp} = \frac{(PV \times Vdp \times L_{dp})}{(1500 \times ddp^2)} + \frac{(YP \times L_{dp})}{(225 \times d_{dp})}$

$\Rightarrow \quad DSPL = PL_{dc} + PL_{dp}$

NOTE: the effects of drill pipe internal upsets are considered negligible. Additional pressure loss for motors, MWD, etc. needs to be added.

4 CALCULATE THE PRESSURE DROP ACROSS THE BIT (PSI):

$$BPL = \frac{Q^2 \times KMW}{12031 \times A^2}$$

5 DETERMINE APL:

$$\Rightarrow APL = \overset{\text{measured}}{SCRP} - \underset{\text{calculated in \#3 above}}{DSPL} - \overset{\text{measured}}{SPL} - \underset{\text{calculated in \#4 above}}{BPL}$$

An example calculation follows:

APPENDIX

ANNULAR PRESSURE LOSS (APL) CALCULATION SHEET

Transocean Annular Pressure Loss Calculation Sheet

This calculation is for a reduced flow rate (SCR) of: 30 GPM

Measured surface equip. pressure losses (SPL): 10 SPM, 30 GPM, 35 psi

Measured SCR pressure at total depth (SCR): 10 SPM, 30 GPM, 290 psi

Required Information

Measured depth (MD)	8500 ft	Drill pipe ID (d_{dp})	3 in
Mud density	8.00 ppg	Drill pipe length (L_{dp})	7700 ft
Mud YP	10 lb/100 ft	Drill collar ID (d_{dc})	2.75 in
Mud PV	8 cP	Drill collar length (L_{dc})	800 ft
TFA of bit (A)	0.5 in²		

Average Fluid Velocity in Drill Pipe and Collars

Drill collars: V_{dc} = GPM ÷ (2.448 x d_{dc}^2)
= (30) ÷ (2.448 x (2.75)²) = 1.62 ft/sec

Drill pipe: V_{dp} = GPM ÷ (2.448 x d_{dp}^2)
= (30) ÷ (2.448 x (3)²) = 1.36 ft/sec

Drill String Frictional Pressure Losses (DSPL)

Note: Assumes flow is Laminar using Bingham Plastic equation

Drill collars: PL_{dc} = (PV x V_{dc} x L_{dc}) / (1500 x d_{dc}^2) + (YP x L_{dc}) / (225 x d_{dc})

PL_{dc} = (8 x 1.62 x 800) / (1500 x (2.75)²) + (10 x 800) / (225 x 2.75)

PL_{dc} = (10371.20) / (11343.75) + (8000) / (618.75) = 14 psi

Note: Assumes flow is Laminar using Bingham Plastic equation

Drill pipe: PL_{dp} = (PV x V_{dp} x L_{dp}) / (1500 x d_{dp}^2) + (YP x L_{dp}) / (225 x d_{dp})

PL_{dp} = (8 x 1.36 x 7700) / (1500 x (3)²) + (10 x 7700) / (225 x 3)

PL_{dp} = (83873) / (13500) + (77000) / (675) = 120 psi

DSPL = PL_{dc} + PL_{dp} = 14 + 120 = 134 psi

Pressure Drop across the bit (BPL)

BPL = (Q^2 x KMW) ÷ (12031 x A^2)
= (30² x 8) ÷ (12031 x (0.5)²) = 2 psi

Annular Pressure Losses (APL)

APL = SCR - DSPL - SPL - BPL = (290) - (134) - (35) - (2)

APL = 78 PSI

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1 DRILLSTRING COMMUNICATION

Data

Initial SIDPP = 120 psi
Initial SICP = 620 psi
Mud Weight = 15.3 ppg
(0.796 psi/ft)
Pit Gain = 9.5 bbls
Overbalance Margin = 150 psi
Operating Margin = 100 psi

Hole Size = 8-1/2"
Drillpipe OD = 5"
Annular Capacity = 0.0456 bbl/ft
(8.5" hole with 5" DP)
Hole Depth = 12,250 ft TVD

Example 1

1. Record SIDPP and SICP at fixed intervals and determine the migration rate (MR).

$$MR = \frac{(P2 - P1)}{MW \times (T2 - T1)} = \frac{(1018 - 620)}{0.796 \times (60 - 30)} = 16.67 \text{ ft/min} = 1000 \text{ ft/hr}$$

Where,
P1 = Initial stabilized SICP (psi)
P2 = SICP at time T2 (psi)
T1 = Time initial SICP recorded (min)
T2 = Time P2 SICP was recorded (min)
MW = Mud weight (psi/ft) (i.e. MW (ppg) x 0.052)

2. Allow the SIDPP to build to an overbalance margin (150 psi) over initial stabilized shut-in pressure.

Initial SIDPP = 120 psi
Overbalance = 150 psi
SIDPP + Overbalance = 120 + 150 = 270 psi

3. Allow the SIDPP to build by a further operating margin (100 psi) over Step 2 above.

(SIDPP + Overbalance) + Operating Margin = 270 + 100 = 370 psi

4. Calculate the loss in hydrostatic pressure for mud bled-off from the choke.

$$\text{Hydrostatic Pressure Loss (psi/bbl)} = \frac{\text{MW (psi/ft)}}{\text{Annulus Capacity (bbl/ft)}}$$

$$HPL = \frac{0.796}{0.0459} = 17.34 \text{ psi/bbl}$$

5. Operating Margin = 100 psi. This equates to 5.7 bbls of mud at 15.3 ppg.
   100 psi ÷ 17.34 psi/bbl = 5.7 bbls

6. Once SIDPP reaches 370 psi, bleed off slowly from the choke (maintaining constant casing pressure) until the SIDPP is reduced to the original stabilized shut-in pressure plus the overbalance margin (i.e. 270 psi).

   Note: In theory this should take 5.7 bbls. Be aware that there will be a considerable lag time between choke manipulations and corresponding changes in the drillpipe pressure.

7. Allow the SIDPP to build by the operating margin (100 psi), then repeat Step 6 and bleed off an additional 5.7 bbls of mud to allow the pressure to reduce to the original stabilized shut-in pressure plus the overbalance margin.

8. Continue this operation until the kick has reached the BOPs.

9. Lubricate mud to remove the influx from the well.

   Note: Depending on migration rate and the length of the hole, this operation can take a long time.

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Volumetric Worksheet - Example #1

A Time	B Operation	C Casing Pressure (psi)	D Change in Casing Pressure (psi)	E Drillpipe Pressure (psi)	F Change in DP Pressure (+/- psi)	G Mud bled-off at Choke (bbl)	H Hydrostatic Loss (psi)	I Total Mud Bled-Off (bbl)	J Over Balance Pressure (psi)	K Comments
	Shut-in Well (Gain 9.5 bbl)									
7:30	Initial stabilized pressures	820		120						
	Overbalance Margin (150 psi)			270	+150				+150	
	Operating Margin (100 psi)			370	+100				+250	
[illegible]:45	Bleed back to DP=270 psi			270	-100	5.7	100	5.7	+150	
	Allow press to build to 370psi			370	+100				+250	
[illegible]:45	Bleed back to DP=270 psi			270	-100	5.7	100	11.4	+150	
	Allow press to build to 370psi			370	+100				+250	
10:30	Bleed back to DP=270 psi			270	-100	5.7	100	17.1	+150	
	Allow press to build to 370psi			370	+100				+250	
11:15	Bleed back to DP=270 psi			270	-100	5.7	100	22.8	+150	
	Allow press to build to 370psi			370	+100				+250	
11:45	Bleed back to DP=270 psi			270	-100	5.7	100	28.5	+150	
	Allow press to build to 370psi			370	+100				+250	

Migration Rate
MR (ft/min) = $\frac{(P2 - P1)}{MW \times (T2 - T1)}$

P1 = Casing Pressure at Time 1 (psi)
P2 = Casing Pressure at Time 2 (psi)
MW = Mud Weight (psi/ft) ie. Mud Weight PPG x 0.052
T1 = Time when P1 was recorded (min)
T2 = Time when P2 was recorded (min)

NOTE
If the drillstring becomes plugged, monitor the SICP and follow the Well Control Manual Section 8.3.1.2

2 NO DRILLSTRING COMMUNICATION

Data

Initial SIDPP = 120 psi
Initial SICP = 620 psi
Mud Weight = 15.3 ppg
(0.796 psi/ft)
Pit Gain = 9.5 bbls
Overbalance Margin = 150 psi
Operating Margin = 100 psi

Hole Size = 8-1/2"
Drillpipe OD = 5"
Annular Capacity = 0.0456 bbl/ft
(8.5" hole with 5" DP)
Hole Depth = 12,250 ft TVD

Example 2

If the drillstring becomes plugged when on bottom, the bit is off bottom or out of the hole, and gas is migrating, the following situation should be adopted (reference Section 6 Subsection 3 Item 1.2).

10. Monitor and record SICP at fixed intervals and determine the migration rate (MR).

$$MR = \frac{(P2 - P1)}{MW \times (T2 - T1)} = \frac{(1018 - 620)}{0.796 \times (60-30)} = 16.67 \text{ ft/min} = 1000 \text{ ft/hr}$$

Where,
P1 = Initial stabilized SICP (psi)
P2 = SICP at time T2 (psi)
T1 = Time initial SICP recorded (min)
T2 = Time P2 SICP recorded (min)
MW = Mud weight in psi/ft (i.e. MW (ppg) x 0.052)

11. Allow the SICP to build to an overbalance margin (150 psi) over initial stabilized shut-in pressure.

Initial SICP = 620 psi
Overbalance = 150 psi
SICP + Overbalance = 620 + 150 = 770 psi

12. Calculate the loss in hydrostatic pressure for mud bled-off from the choke.

    $$\text{Hydrostatic Pressure Loss (psi/bbl)} = \frac{\text{MW (psi/ft)}}{\text{Annulus Capacity (bbl/ft) or Open Hole Capacity (bbl/ft)}}$$

    $$\text{HPL} = \frac{0.796}{0.0459} = 17.34 \text{ psi/bbl}$$

13. Allow the SICP to build by a further operating margin (100 psi) over Step 2 above.

    (SICP + OB) + Operating Margin = 770 + 100 = 870 psi

14. Calculate the volume of mud in the annulus that would equate to the 100 psi operating margin.

    Operating Margin = 100 psi = 5.7 bbls at 15.3 ppg

    100 psi ÷ 17.34 psi/bbl = 5.7 bbls

15. Once SICP reaches 870 psi, bleed off slowly from the choke (maintaining constant casing pressure) until the calculated volume equal to 100 psi (i.e. 5.7 bbls) has been returned to the trip tank.

16. Allow the SICP to build by another 100 psi (i.e. until SICP = 970 psi).

17. Once SICP reaches 970 psi, bleed off slowly from the choke (maintaining constant casing pressure) until the calculated volume equal to 100 psi (i.e. 5.7 bbls) has been returned to the trip tank.

18. Repeat Steps 7 and 8 until the influx reaches the BOP.

19. Lubricate mud to remove the influx from the well or use the dynamic well control procedure.

    Calculation for Time Taken to Bleed from Annulus:

    Using Boyle's Law, calculate the pressure of the influx after bleed-off:

    P1 x V1 = P2 x V2

Where,
V1 = 9.5 bbl (initial pit gain)
V2 = 9.5 + Operating Margin bleed-off (5.7 bbls) = 15.2 bbls
P1 = Initial Influx Pressure
P1 = [Well TVD (ft) x Mud Gradient (psi/ft)] + Initial Stabilized DP Pressure
P2 = Influx pressure after bleed-off.

$$P2 = \frac{P1 \times V1}{V2}$$

$$P2 = \frac{[(12250 \times 0.796) + 120] \times 9.5}{(9.5 + 5.7)}$$

P2 = 6169 psi

Calculate the position of the top of the influx based on annulus hydrostatic pressures.

Mud Hydrostatic above influx = 6169 – 870 (choke pressure at first bleed-off)
= 5299 psi

Top of influx = 5299 ÷ Mud Gradient (psi/ft)
= 5299 ÷ 0.796 = 6657 ft TVD

Calculate the length of the influx.

$$\text{Influx Length} = \frac{\text{Influx Volume (bbl)}}{\text{Annulus Capacity (bbl/ft)}} = \frac{15.2}{0.0459} = 331 \text{ ft}$$

Calculate the depth at the bottom of the influx.

Top of Influx = 6657 ft TVD
Length of Influx = 331 ft
Bottom of Influx = 6657 + 331 = 6988 ft TVD

Calculate the distance the influx has traveled and thus, from the migration rate, the time taken to perform the first 5.7 bbl bleed-off.

Distance Traveled = TD – Initial Migration (Overbalance + Operating Margins)
– Bottom depth of Influx after Bleed-off
= 12250 – 314 – 6988 = 4948 ft

Migration Rate = 1000 ft/hr

Therefore, Time to Bleed = 4948 ÷ 1000 = 4.9 hours = 297 minutes

APPENDIX

STATIC VOLUMETRIC WELL CONTROL

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Volumetric Worksheet - Example #2

A Time	B Operation	C Casing Pressure (psi)	D Change in Casing Pressure (psi)	E Drillpipe Pressure (psi)	F Change in DP Presure (+/- psi)	G Mud bled off at Choke (bbl)	H Hydrostatic Loss (psi)	I Total Mud Bled-Off (bbl)	J Over Balance Pressure (psi)	K Comments
	Shut-in Well (Gain 5.5 bbl)									
2:30	Initial Stabilized Pressures	620		0						No Drillpipe Communication
	Overbalance Margin (150 psi)	770	+150						+150	
	Operating Margin (100 psi)	870	+100						+250	
7:45	Bleed off Cp Margin (5.7 bbl)	870	--			5.7	100	5.7	+150	
	Allow Op margin to build	970	+100						+250	
9:45	Bleed off Cp Margin (5.7 bbl)	970	--			5.7	100	11.4	+150	
	Allow Op margin to build	1070	+100						+250	
10:30	Bleed off Cp Margin (5.7 bbl)	1070	--			5.7	100	17.1	+150	
	Allow Op margin to build	1170	+100						+250	
11:15	Bleed off Cp Margin (5.7 bbl)	1170	--			5.7	100	22.8	+150	
	Allow Op margin to build	1270	+100						+250	
11:45	Bleed off Cp Margin (5.7 bbl)	1270	--			5.7	100	28.5	+150	
	Allow Op margin to build	1370	+100						+250	

Migration Rate

$$MR\ (\text{ft/min}) = \frac{(P2 - P1)}{MW \times (T2 - T1)}$$

P1 = Casing Pressure at Time 1 (psi)
P2 = Casing Pressure at Time 2 (psi)
MW = Mud Weight (psi/ft) ie. Mud Weight PPG x 0.052
T1 = Time when P1 was recorded (min)
T2 = Time when P2 was recorded (min)

NOTE:
If the drillstring becomes plugged, monitor the SICP and follow the Well Control Manual Section 6.3.1.2

Bullheading procedures are produced with reference to the particular circumstances at the rig site. For example, during a work over operation a procedure for bullheading will be drawn up along the following lines:

- Calculate the surface pressure that will cause formation fracturing during the bullheading operation.
- Calculate the tubing (or drill pipe) burst pressure as well as casing burst (to cover the possibility of tubing/drillpipe failure during the operation).
- Calculate static tubing head (or drillpipe) pressure during bullheading.
- Slowly pump fluid down the tubing/drillpipe. Monitor pump and casing pressure during the operation.
- As an example, consider the following well which is to be killed by bullheading brine down the tubing:

Data

Depth of formation/top perforation		= 10,000 feet TVD
Formation pressure, EMW_{pf}		= 9 ppg
Formation fracture pressure, EMW_{pfb}		= 14 ppg
Tubing 4 ½", N80,1.6 #	Internal capacity	= 0.0155 bbls/ft
	Internal yield	= 7,774 psi
Shut-in tubing head pressure		= 3,650 psi
Gas density		= 0.1 psi/ft

Calculations

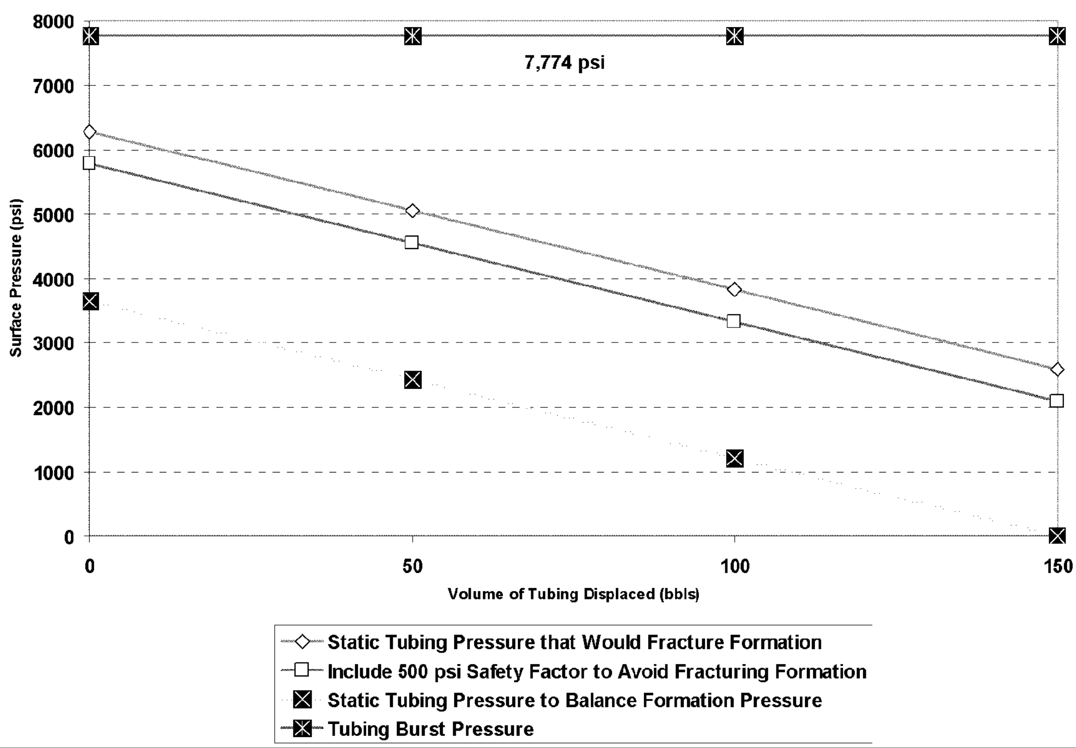
- Total internal volume of tubing
  = 10,000 ft x 0.0155 bbls/ft = 155 bbls
- Maximum allowable pressure at pump start up
  = (14 ppg x 0.052 x 10,000 ft) - (0.1 psi/ft x 10,000 ft) = 6,280 psi
- Maximum allowable pressure when the tubing has been displaced to 9ppg brine
  = (14 ppg - 9 ppg) x 0.052 x 10,000 ft = 2,600 psi
- Static tubing head pressure at initial shut-in
  = 3,650 psi
- Static tubing head pressure when tubing has been displaced to brine
  = 0 psi (i.e. the tubing should be dead)

The above values can be represented graphically (as shown in the Figure 10.11.1 below). This plot can be used as a guide during the bullheading operation.

APPENDIX

BULLHEADING CALCULATIONS

Figure 10.11.1



APPENDIX
MUD GAS SEPARATOR (MGS) DESIGN

1 DESIGN

The MGS can only operate effectively and safely if a sufficient mud seal is maintained on the discharge line:

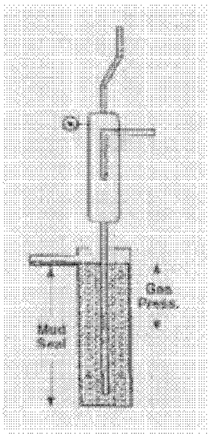


Figure 10.12.1
Circulating Gas through MGS within Design Capacity

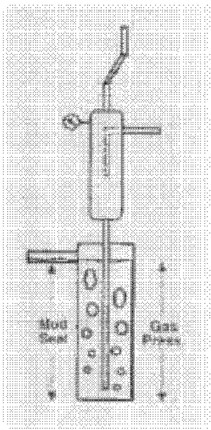


Figure 10.12.2
Circulating through MGS outwith Design Capacity (unloading gas)

NOTE: **The mud seal is often created by use of a 'U-tube'.**

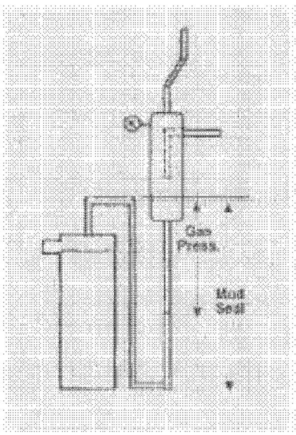


Figure 10.12.3
Possible Improvement of Mud Seal Height

To operate safely, the rig crew should have some means of controlling the internal MGS pressure and procedures to follow if the maximum operating criteria are reached or exceeded.

The most common method of measuring the internal MGS pressure is installation of a very low pressure gauge 0-20 psig (0-150 kPa, 0-1.4 bar) or pressure transmitter on the separator vessel; the maximum operating criterion in this case corresponds to the hydrostatic head provided by the mud seal

Should MGS overloading occur, consideration should be given to:

- Changing to a slower kill rate.
- Switching the choke and kill manifold outlet to a high pressure overboard line or production facilities.
- Using the volumetric method to evacuate the gas from the annulus.

1.1 SYSTEM DESIGN

It is essential to verify that the system is capable of handling the maximum amount of fluid and gas that could be produced by the well in the case of a severe kick. That value should be obtained from the Operator and should be compared to the system capacity according to the Company.

NO MODIFICATION SHALL BE DONE TO EXISTING SYSTEMS WITHOUT PRIOR REVIEW AND APPROVAL BY THE REGION OFFICE.

In case of doubt concerning the capacity of the MGS system on a rig, the Operations Manager Performance should contact the Well Operations Group with the following information:

- Maximum expected or required gas flow rate.
- Separator vessel drawing showing diameter, length and internal arrangement
- Drawing or sketch of vent line showing line dimension, length, position and number of elbows and other restrictions.
- Drawing or sketch showing the arrangements, length and size of the separator discharge line and mud seal.

DOCUMENT CONTROL PAGE

APPROVALS

Endorsed by: LDMcMahan — Executive Signature | Larry McMahan — Name | VP of Performance — Position

Approved by: Signature | Steve Hand — Name | Well Operations Manager — Position

TABLE OF REVISIONS

Revision No.	Revision Date	Description of Change	Prepared By	Position	Reviewed By	Position
Issue: 03 Revision: 00	March 31, 2008	New Issue	Steve Hand	Well Operations Manager	Larry McMahan	VP of Performance
Issue: 03 Revision: 01	March 31, 2009	**09-1**, Guidance on boosting while tripping **Section 1 Well Control Procedures and Responsibilities - sub-section 2, page 5**	Steve Hand	Well Operations Manager	Larry McMahan	VP of Performance
Issue: 03 Revision: 01	March 31, 2009	**09-1**, Guidance on boosting while tripping **Section 4 Preparation and Prevention – sub-section 4, page 6**	Steve Hand	Well Operations Manager	Larry McMahan	VP of Performance
Issue: 03 Revision: 01	March 31, 2009	**09-2**, Guidance on Maximum Anticipated Surface Pressure **Section 2 Well Planning Considerations - sub-section 4, page 1**	Steve Hand	Well Operations Manager	Larry McMahan	VP of Performance
Issue: 03 Revision: 01	March 31, 2009	**09-3**, Guidance on well control drills – mud loggers **Section 4 Preparation and Prevention - sub-section 2, page 3**	Steve Hand	Well Operations Manager	Larry McMahan	VP of Performance
Issue: 03 Revision: 01	March 31, 2009	**09-4**, Guidance on drill pipe fill-up **Section 4 Preparation and Prevention - sub-section 4, page 4**	Steve Hand	Well Operations Manager	Larry McMahan	VP of Performance
Issue: 03 Revision: 01	March 31, 2009	**09-5**, Guidance on stripping operations **Section 6 Well Kill Techniques- sub-section 5, page 2**	Steve Hand	Well Operations Manager	Larry McMahan	VP of Performance
Issue: 03 Revision: 01	March 31, 2009	**09-6**, Guidance on wire line considerations **Section 7 Well Control Complications/Emergency - sub-section 1, page 6**	Steve Hand	Well Operations Manager	Larry McMahan	VP of Performance
Issue: 03 Revision: 01	March 31, 2009	**09-7**, Guidance on HPHT flow checks **Section 8 Specific Environments - sub-section 5, page 4**	Steve Hand	Well Operations Manager	Larry McMahan	VP of Performance

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Issue: 03 Revision: 01	March 31, 2009	**09-8**, Guidance on shooting nipples **Section 9 Well Control Equipment - sub-section 5, pg 5**	Steve Hand	Well Operations Manager	Larry McMahan	VP of Performance
Issue: 03 Revision: 01	March 31, 2009	**09-9**, **Section 1, Well Control Procedures and Responsibilities - sub-section 4, pg 1,** added Derrickman to Well Control training requirements in Table 1.4.1.	Steve Hand	Well Operations Manager	Larry McMahan	VP of Performance
Issue: 03 Revision: 01	March 31, 2009	**09-10**, **Section 4, Preparation and Prevention - sub-section 1, pg 1,** note added on minimum material requirement.	Steve Hand	Well Operations Manager	Larry McMahan	VP of Performance
Issue: 03 Revision: 01	March 31, 2009	**09-11**, **Section 5, Action Upon Taking a Kick - sub-section 3,** comments added to emphasize riser monitoring and readiness to divert.	Steve Hand	Well Operations Manager	Larry McMahan	VP of Performance
Issue: 03 Revision: 01	March 31, 2009	**09-13**, **Section 6, Well Kill Techniques - sub-section 8,** clarified procedure.	Steve Hand	Well Operations Manager	Larry McMahan	VP of Performance
Issue: 03 Revision: 01	March 31, 2009	**09-14**, **Section10, Appendix - sub-section 5,** added notes below conversion table	Steve Hand	Well Operations Manager	Larry McMahan	VP of Performance
Issue: 03 Revision: 01	March 31, 2009	**09-15**, **Section 2.4, 3.2, 4.4, 6.4, 8.3, 8.4, 8.6 9.4, 10.7, 10.8, 10.11**, re-formatted figures.	Steve Hand	Well Operations Manager	Larry McMahan	VP of Performance