



**Great South Land**  
Minerals Limited

Great South Land Minerals Limited ABN 54 068 650 386

# **DRILLING OPERATIONS MANUAL**

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1	Feb 2008	All	New Operator	DMN

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**INTRODUCTION**

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## 1.1 DISTRIBUTION LIST

**Controlled** electronic copy held by Drilling manager

**Uncontrolled** hard copies of this document are distributed as follows:

Copy No.	Holder
1	Drilling Manager (GSLM office copy)
2	Drilling Supervisor (Rig copy)
3	Drilling Contractor (Office copy)
4	Contractors Rig Manager (Rig copy)
5	Mineral Resources Tasmania
6	

**Table 1            Holders of Copies of GSLM's Drilling Operations Manual**

## 1.2 PURPOSE

The purpose of the Drilling Operations Manual is to:

- Illustrate the policies, standards, guidelines, procedures and controls required during the drilling of wells.
- Provide a guide for relevant personnel on the procedures to be followed to ensure that a consistent, thorough and uniform approach is adopted to facilitate delivery of cost-effective wells.
- Provide sufficient information to allow the Drilling Supervisor to supervise, and monitor the drilling operation and control standards and reporting
- .Provide sufficient information which can be used as a reference in planning and field drilling operations.

## 1.3 APPLICATION

The Drilling Operations Manual is the reference manual for GSLM, Drilling Supervisors and Drilling Managers controlling the drilling operations of land wells in Tasmania.

## 1.4 INTRODUCTION

It is acknowledged that this manual is based on the Drilling Operations Manual used by several operators in the Cooper Basin of South Australia. It is expected that these operations will be very similar to those in Tasmania.

Tasmania is largely unexplored and therefore all personnel have to be aware that unplanned events could occur at any time. All personnel need to be aware of this and trained to react correctly. In all circumstances the safety of the public and personnel on the rig is the prime concern and operations should be carried out with safety as the top priority.

## **1.5 SAFETY**

GSLM is committed to providing a safe and healthy work environment and to protecting its employees from the possibility of injury and risk to health while they are at work.

The company will make available the appropriate resources to ensure that it complies in all respects to the relevant occupational health and safety legislation and to ensure that the workplace is safe and healthy. In order to achieve this GSLM will ensure that:

- A safe working environment and safe systems of work are provided and maintained at the wellsite.
- Equipment is "Fit for Purpose" and maintained in safe condition.
- People working on the rig will be provided with the information, instruction, training, equipment and supervision needed to ensure their health and safety.
- Occupational health and safety standards and procedures are continually reviewed and improved.
- Risk management procedures are in place to identify, assess and control/eliminate hazards. These will include, Work Permits, JSA's, safety meetings, incident reports, rig inspections etc.

All personnel must be trained, capable and certified (where applicable) for the job they are doing. It is the responsibility for the contractor to ensure their personnel are qualified and trained for the job. The DSV should check qualifications where possible prior to the job commencing.

In the event of an incident or emergency at the rig the priorities will be as follows:

- Safety to the Public
- Safety to personnel on the rig
- Environmental Protection
- Prevention of damage to equipment

The current workplace health and safety legislation in Tasmania is:



The Workplace Health and Safety Act 1995



The Workplace Health and Safety Regulations 1998



The Workers Rehabilitation and Compensation Act 1988

## 1.6 DEFINITIONS

This section contains the abbreviations and terminology used in this Manual. It is strongly recommended that all readers familiarise themselves with the abbreviations and terminology used, to avoid any misunderstanding arising from the use of the terms in the text.


### 1.6.1 Abbreviations

<b>AC</b>	Alternating Current	<b>AHD</b>	Along Hole Depth
<b>API</b>	American Petroleum Institute	<b>BHA</b>	Bottom Hole Assembly
<b>Bbls</b>	Barrels	<b>bpm</b>	Barrels per Minute
<b>BOP</b>	Blowout Preventer	<b>CCL</b>	Casing Collar Locator
<b>BUR</b>	Build-up Rate	<b>cmt</b>	Cement
<b>CBL</b>	Cement Bond Log	<b>CET</b>	Cement Evaluation Tool
<b>Cu</b>	Cubic		
<b>DC</b>	Drill Collar	<b>DDE</b>	Directional Drilling Engineer
<b>DDR</b>	Daily Drilling Report	<b>DE</b>	Drilling Engineer
<b>DOM</b>	Drilling Operations Manual	<b>DP</b>	Drill Pipe
<b>DSV</b>	Drilling Supervisor	<b>DST</b>	Drill Stem Test
<b>E &amp; D</b>	Exploration and Development	<b>ECD</b>	Equivalent Circulating Density
<b>EMW</b>	Equivalent Mud Weight	<b>EOB</b>	End of Build-up
<b>FIT</b>	Formation Integrity Test	<b>FPIT</b>	Free Point Indicator Tool
<b>ft</b>	Feet	<b>GSLM</b>	Great South Land Minerals
<b>gal</b>	Gallon	<b>GLG</b>	Geologist
<b>gpm</b>	Gallons per Minute	<b>GR</b>	Gamma ray
<b>HSWE</b>	Health, Safety, Welfare and Environment	<b>ht</b>	Height
<b>HTB</b>	High Temperature Blend	<b>HWDP</b>	Heavy Weight Drill Pipe
<b>IADC</b>	International Association of Drilling Contractors	<b>ID</b>	Inside Diameter
<b>IF</b>	Internal Flush		
<b>KOP</b>	Kick-off Point	<b>KB</b>	Kelly Bushing
<b>LCM</b>	Lost Circulation Material	<b>LGS</b>	Low Gravity Solids
<b>MAASP</b>	Maximum Allowable Annular Test Surface Pressure	<b>MBT</b>	Methylene Blue
<b>MDT</b>	Modular Dynamic Tool	<b>min</b>	Minute
<b>MMS</b>	Magnetic Multi Shot	<b>MSS</b>	Magnetic Single Shot
<b>MT</b>	Metric Tonnes	<b>MSDS</b>	Materials Safety Data Sheet
<b>MWD</b>	Measurement While Drilling	<b>MW</b>	Mud Weight
<b>N/A</b>	Not Applicable	<b>NBRR</b>	Near Bit Roller Reamer
<b>NDT</b>	Non Destructive Testing	<b>NMDC</b>	Non Magnetic Drill Collar
		<b>NRV</b>	Non Return Valve System
<b>OD</b>	Outside Diameter	<b>OE</b>	Operations Engineer
<b>OGL</b>	Operations Geologist	<b>OH</b>	Open Hole System
<b>P &amp; A</b>	Plug and Abandon	<b>PE</b>	Petroleum Engineer
<b>Pfc</b>	Final Circulating Pressure	<b>Pic</b>	Initial Circulating Pressure
<b>ppg</b>	Pounds per Gallon	<b>POOH</b>	Pull out of Hole
<b>psi</b>	Pounds per square inch	<b>ppm</b>	Parts per Million
<b>PVT</b>	Pressure Volume Temperature.	<b>PV</b>	Plastic Viscosity
<b>QA/QC</b>	Quality Assurance/ Quality Control		
<b>RFT</b>	Repeat Formation Tester	<b>RIH</b>	Run in Hole
<b>ROP</b>	Rate of Penetration	<b>rpm</b>	Revolutions per Minute
<b>RT</b>	Rotary Table		
<b>SCR</b>	Slow Circulating Rate	<b>sec/ qt</b>	Seconds per quart
<b>SEO</b>	Statement of Environmental Objectives	<b>SF</b>	Safety Factor
<b>SICP</b>	Shut-in Casing Pressure	<b>SIDPP</b>	Shut-in Drill Pipe Pressure
<b>SITHP</b>	Shut-in Tubing Head Pressure	<b>spm</b>	Strokes per Minute
<b>sx</b>	Sacks		
<b>TOC</b>	Top of Cement	<b>TP</b>	Tool Pusher
<b>TVD</b>	True Vertical Depth	<b>TD</b>	Total Depth
<b>UHF</b>	Ultra High Frequency	<b>TLC</b>	Tough Logging Conditions
<b>USIT</b>	Ultra sonic imaging tool)		
<b>VDL</b>	Variable Density Log		
<b>WGL</b>	Wellsite Geologist		
<b>WOC</b>	Waiting on Cement	<b>WOB</b>	Weight on Bit
<b>wt</b>	Weight		










### **1.6.2 Language**

- **Shall** or **must** indicates a mandatory requirement.
- **Should** indicates a guideline which is strongly recommended.
- **May** indicates a guideline which is to be considered.

## **1.7 REFERENCES**

All references applicable to a section of the text are identified at the foot of the text and prefixed by the  symbol.

This manual should be used in conjunction with the following references.

	GSLM's Policies and Procedure
	Dangerous Goods Act 1998
	Mineral Resources Development Act 1995
	Mineral Resources Regulations 2006
	Mineral Exploration Code Of Practice
	Schedule C of the Exploration License
	The Workplace Health and Safety Act 1995
	The Workplace Health and Safety Regulations 1998
	The Workers Rehabilitation and Compensation Act 1988

## **CHAPTER 2**

### **QUICKLOOK DRILLING OPERATIONS GUIDE**

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## **2.1 OBJECTIVES**

The objective of the Quicklook Drilling Operations Guide is to provide a quick reference for a newly assigned Rig Supervisor to the drilling activities carried out by GSLM. The table in Section 2.2 summarises and outlines the sequential steps involved in planning, constructing, evaluating and abandoning a typical conventional well. The table incorporates references to procedures contained in this Manual, and where relevant, the applicable forms which must be completed.



## 2.2 QUICKLOOK DRILLING OPERATIONS GUIDE

Summary	DOM Chapter	Forms
<b>Preparing Site and Rig -Up</b>		
Ensure all Regulatory and GSLM approvals have been given		
Ensure new location has been inspected and accepted by Drilling Contractor		
Toolpusher should notify local authorities of rig move timing		
Ensure wellsite and camp locations are prepared before the rig arrives.		
Ensure the turkeys nest is filled and water source recorded		
Check rig move distance. Report on morning report.		
Ensure the sump is prepared and lined if required.		
Ensure the rubbish and sewage handling systems are in place.		
Ensure a plastic sheet is positioned between the rig tanks and sump to prevent washing out of the tank base.		
Check condition of roads. Notify DM of any problems. Check for power lines etc.		
Make up pre-spud equipment list including mud chemicals, bits, surface casing, cementing equipment and Bradenhead.		
<b>Pre-spud Checks</b>		
On first well of the program ensure 3 <sup>rd</sup> party rig inspection is carried out and an action plan prepared for all critical items.		
Ensure rig is completely rigged up and work through Pre-spud Checklist.	3	
Ensure the conductor is set in the cellar correctly.		
Ensure all materials and equipment and back-ups are on site for drilling, casing and cementing the surface hole.	3, 5	
Check that the equipment delivered is what was ordered.		
Ensure adequate supplies of weighting material and LCM are available.	5	
Ensure a water sample is sent to the cementing company for analysis.	8	
Ensure downhole drilling tools (i.e. stabilisers, jars, bits, etc.) are in good condition and within wear limits and hours of usage.	3	
Check grade and specification of casing.	7	
Check Bradenhead matches casing and Drilling Program requirement.	11, 14	
Make up as much new mud as possible prior to spud. If water quality poor consider using fresh to pre-hydrate gel.		
Perform Pre-spud Safety Meeting		
<b>Constructing Cellar</b>		
Ensure the cellar has been dug and the cellar ring installed prior to rig move.		
<b>Setting Conductor (This may be predrilled before rig arrives)</b>		
Auger surface hole to 5-8 m below cellar floor. Set in firm clay.	7	
Ensure the conductor is vertical, the flange level and 'plumb bobbed' central.		
Ensure the conductor is cemented in place. Use 1% CaCl <sub>2</sub> as accelerator	8	
<b>Drilling Surface Hole (This may be predrilled before rig arrives)</b>		
Ensure bit program, BHA design, survey requirements and mud properties are detailed in the Drilling Program.	3	
Drill-out of conductor with reduced flowrate until drill collars are below conductor to prevent washing out the cellar. Gradually increase flowrate so as to prevent mudrings.		
Drill to programmed casing depth and check the bottoms up sample for consolidated formation. Allow a maximum of 3 m of rathole below casing shoe.		
Wiper trip as required to maintain good hole condition.		
Survey at 30 m KB and every 150 m thereafter.		
Circulate hole clean (Minimum 1.5 times annular volume).	3	
Perform wiper trip at interval TD back to previous wiper trip depth	3	
Strap pipe whilst POOH.		
Grade bit.		
Order cement from cementing contractor. Provide cementing contractor with hole and casing details and ensure they confirm cement volumes.		
<b>Running Surface Casing</b>		
Number, measure and drift casing joints. Clean and inspect casing threads. DO NOT USE DIESEL TO CLEAN THREADS	7	
Space out casing so that Bradenhead flange depth suits rig.	7	
Prepare Casing Tally and adjust section TD to allow for 3m rathole below shoe	7	
Use 2 joint shoetrack. Threadlock shoetrack and centralise as per Drilling Program.	7	
Check circulating swedge to ensure it is the correct size and has the correct threads.		
Pick up casing using suitable thread protectors. Make up circulating swedge and wash last joint down. Do not tag bottom.	7	

Summary	DOM Chapter	Forms
<b>Cementing Surface Casing</b>		
Circulate hole and treat Drilling Fluid (if required) prior to cementing.	8	
Pump spacer.	8	
Load cement head with plugs (top and bottom).	8	
Ensure all lines are pressure tested.	8	
Discuss all cement calculations with DM, prior to cement job.	8	
Mix and pump slurries.	8	
Displace with mud using cementing pump.	8	
Do not over displace more than theoretical, plus half shoetrack volume.	8	
If plug bumps, pressure test casing to 80% of rated burst pressure, bleed-off pressure and measure backflow. Check floats holding	8	
If plug does not bump. Bleed-off pressure and measure backflow. Pressure test casing prior to drilling out. Check floats holding.		
Run cement stinger and perform top up cement job with cement unit.	8	
<b>Installing Bradenhead.</b>		
Wait on Cement until surface samples set.		
Slack-off casing		
Back-out landing joint.		
Prior to job check specifications and part numbers of Bradenhead.		
Install Bradenhead as per manufacturer's procedure.	14	
Install BOPs and pressure test BOPs and kill/choke lines (test pressures according to the Drilling Program). If possible test BOP's (on test stump) and choke manifold while drilling surface hole.	10	
Run wear bushing.		
<b>Drilling Intermediate/ Main Hole</b>		
Ensure all equipment is on site to drill entire hole section.	3	
Ensure bit program, BHA design, survey requirements and mud properties are detailed in the Drilling Program.	3	
Drill-out shoe track with mud. Drill maximum of 3 m of new hole		
Circulate hole until mud weight even. Perform LOT	9	
Drill ahead. Make wiper trips approximately every 24hrs if required by hole condition.		
Change bits as required.		
Run wireline surveys every 150 m. Circulate hole prior to each survey. If deviation increases above 3° consider running surveys every 45 m.		
Trip sheets to be filled out on each trip out of the hole. If potential reservoir has been penetrated then trip sheets should also be used on all trips in the hole as well.		
Flow check any significant drilling breaks or unexplained changes in pit volume.		
Control drill as requested by Wellsite Geologist to aid evaluation.		
Adjust mud properties as required to maintain good hole conditions.		
Monitor hours on jar and BHA condition.	3	
Grade bit and gauge stabilisers at each bit trip.		
At section TD, circulate and survey prior to POOH.	6	
Strap pipe whilst POOH		
Perform wiper trip at interval TD back to start of last bit run	3	
<b>Logging Open Hole</b>		
Mobilise logging crew prior to POOH. Confirm logging program with Electric Logging company prior to job.	9	
Make sure fishing equipment available for ALL logging tools.	9	
Measure and record size and lengths of all logging tools.	9	
Monitor well on trip tank while logging. Record losses and gains.	9	
<b>Open Hole DST</b>		
Mobilise testing and separator crews if required.	9	
Confirm test program (times, intervals, water cushion etc.) with DE, tester and wellsite geologist prior to test. Make up running list.	9	
Rig up testing manifold, surface lines and separator (if required) and pressure test. Secure/tie down all lines.	9	
RIH with test string. Correlate with CCL/GR if required	9	
DST tools can not be opened during the hours of darkness unless special dispensation is obtained from MRT and a risk assessment done.		
Set/Inflate packers.	9	

Summary	DOM Chapter	
Top-up annulus prior to opening tools.	9	
Open tools and perform test according to the relevant procedure (annulus to be continuously monitored whilst testing).	9	
Prior to POOH, close test tools, release packers, (pull above any thick coals) reverse circulate string contents. Circulate conventionally. DST tools MUST NOT be pulled out of the hole unless string contents have been reverse circulated.		

<b>Running Intermediate and Production Casing</b>		
Change out pipe rams to suit casing.	7	
Number, measure and drift casing	7	
Clean and inspect casing threads	7	
Space-out casing. Refer to Drilling Program for position of marker joints and centralisers	7	
Complete Casing Tally.	7	
Threadlock shoetrack and centralise according to Drilling Program.	7	
Check float equipment.	7	
A two joint shoe track will be run on intermediate casing and a single joint shoe track on production casing.		
Pick up casing using suitable thread protectors.		
Circulating swedge to be available for all grades of casing run.		
Circulate down landing joint.	7	
<b>Cementing Casing</b>		
Discuss cement formulations and calculations with DE prior to cement job. Determine displacement fluid type and weight and make up if required.		
Circulate hole and treat mud (reduce YP) prior to cementing.	8	
Load cement head with plugs. Top and bottom or bottom plug and top ball.	8	
Ensure all lines are tied down and pressure tested.	8	
Pump pre-flush.	8	
Mix and pump slurries as per the cementing contractors cement program	8	
Displace with either rig pumps or cementing unit at pumping rate to give annular velocities approximately the same as when drilling.	8	
On intermediate casing displace with mud. On production casing displace with kill weight brine.		
All mud to be left in annulus or between casings must be treated with Biocide.		
Do not over displace by more than half the shoe track volume on intermediate casing		
Pump to bump on all production casing cement jobs.		
When plug bumps, pressure test casing to 500 psi above bump pressure. Bleed-off pressure and measure backflow. Pressure test casing.	8	
<b>Installing Casing Slips and Tubing/ Casing Spool</b>		
If using tubing spool land spool in bowl. If using casing slips WOC until surface samples set. Pick up BOPs.		
Install slip assembly, slack-off casing, cut casing and install spool according to manufacturers procedure	14	
Install blank flange or adaptor flange on production casing.	14	
<b>Plugging and Abandonment</b>		
All plugs to be minimum 50 m long (25 m above and 25 m below the top of the formation to be isolated).		
Where possible a cement stinger and mule shoe should be used.		
Confirm Cement Program and plug depths with DM. Obtain formation tops from WGL.	11	
Circulate hole prior to cementing. Ensure all lines are pressure tested.	8	
Mix and pump slurry. Displace with mud. Pick up above plug and reverse circulate cement from string.		
Pressure test last casing shoe plug.	11	
Remove Bradenhead and return to logistics base for re-dress.	11	
Dump surface cement plug.		
Install Marker Plate.		
Back-fill cellar.	11	
<b>Cleaning-up Lease</b>		
Ensure lease is cleaned up, rubbish disposed of and pits back-filled.	11	
Complete End of Well Equipment List.		
Complete lease clean up form.		
Ensure Mud reconciliation is filled out and signed.		
Forward all equipment to next location or logistics base.		

**CHAPTER 3**  
**GENERAL DRILLING PRACTICES**

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### **3.1 OBJECTIVES**

The objective is to produce a “fit for purpose” wellbore drilled in accordance with agreed specifications and the standard practices and procedures contained in this Manual.

The criteria for a “fit for purpose” wellbore includes the following, in order of importance:

1. Ensure GSLM's safety procedures are followed.  
These include accident – incident reporting, rig move policies etc.
2. Ensure the drilling rig and equipment is “Fit for Purpose” and remains in this condition for the duration of the well.
3. Drill the well with the risk to personnel, the environment and equipment reduced to as low as reasonably practicable. Ensure the wellbore design meets the requirements of the approved Environmental and Heritage objectives for the well.
4. Penetrate hydrocarbon bearing intervals without formation impairment.
5. Meet the planned trajectory without dogleg severity in excess of 1.5°/30 m (or as specified in the Drilling Program).
6. Provide hole conditions that allow good quality evaluation (logs, cuttings, cores, DST's etc.).
7. Attain the required bottom hole position.

It is the responsibility of the Drilling Contractor to drill the well to the correct specification. The quality of work must be monitored and controlled by the Rig Supervisor with support from the Drilling Manager to ensure that the well and Health, Safety, Welfare and Environmental objectives are not compromised.

The following must be prevented:

1. Injuries to personnel or environmental damage.
2. Well control incidents that affect safety and integrity.
3. Impairment of the reservoir due to poor drilling fluid properties or excessive overbalance which affect logging and production.
4. Dog Legs due to poor trajectory control which may affect casing and completion running.
5. Washouts due to poor flow regimes which ultimately affect the logging operation and log quality.
6. Drilling practices that cause excessive formation damage.

### 3.2 RESPONSIBILITIES

Responsibilities for the implementation, supervision and verification of drilling operations are summarised in the table below.

Task	Performed by	Verified by
Report ALL incidents, near misses	Anybody	DSV / DM
Prepare the Drilling Program	DM	CEO
Select equipment	DM	DSV/CEO
Call-out Company supplied equipment	DSV	DM
Call-out Contractor supplied equipment	DSV	DM
Conduct drills	Drilling Contractor	DSV
Inspect tubulars	Drilling Contractor	DSV
Inspect and test BOP	Drilling Contractor	DSV
Monitor well trajectory	DSV	DM
Program and monitor drilling parameters	DSV / DM	DM
Monitor drilling costs versus plan	DM	CEO
Perform BHA design and bit selection	DSV / DM	DM
Measure and tally tubulars	Drilling Contractor / DSV	DSV
Operate rig equipment safely and properly	Drilling Contractor	DSV
Conduct primary well control when required	Drilling Contractor	DSV
Conduct secondary well control when required	Drilling Contractor	DSV
Decide when to conduct check trips	DSV	DM
Carry out flow checks	Drilling Contractor	DSV
Maintain Trip Sheets in and out of the hole	Drilling Contractor & Mud Loggers	DSV
Report drilling problems	Drilling Contractor	DSV
Maintain adequate drilling fluid, chemical, LCM and cement stocks	Drilling Fluids and Cementing Contractors	DSV

**Table 2. Responsibilities for Implementation, Supervision and Verification of Drilling Operations.**

### **3.3 GENERAL DRILLING STANDARDS**

This section provides an overview of key drilling standards that should be adhered to by the DSV and Drilling Contractor.

#### **3.3.1 Depth Referencing**

All depths (either along hole or true vertical) must be referred to the Rotary Table (RT) of the rig which initially drilled the well (original derrick floor elevation). Depths must be reported in meters.

#### **3.3.2 Chemical Stocks**

The following are the minimum chemical stocks that shall be available for use at all GSLM wellsites (note barite etc may be stored off location):

- Mud chemical stocks adequate to re-build 1½ times the hole and surface volume of the drilling fluid system in use and the interval being drilled.
- Emergency barite stocks to be able to weight the total drilling fluid system by at least 1.0 ppg.
- Sufficient stocks of LCM material for both above and across the reservoir (as a guide should have enough LCM to add 2 lb/bbl to the entire system if required).
- Sufficient stock of surfactant, weightable pipe-freeing agent, Biocide and corrosion inhibitor materials.

These chemical stocks are based on worst lost circulation criteria and known reservoir pressure parameters.

Specific well requirements are individually documented in the Drilling Program.

Only Barite and KCl/NaCl shall be used as a weighting material unless otherwise specified in the Drilling Program.

#### **3.3.3 Equipment Requirements**

The DSV shall ensure that the availability (and serviceability) of equipment is in accordance with GSLM's requirements and the relevant contracts, prior to the commencement of drilling activities. These are summarised below (Sections 3.3.3.1 - 3.3.3.5).

##### **3.3.3.1 Equipment Lists**

Equipment Lists will be provided for each well. They provide an overview of the requirements for each hole interval. Note however that each hole section and each well must be considered separately.

##### **3.3.3.2 Surface Equipment**

Rig surface equipment requirements shall be detailed in the Drilling Contractor's contract. Critical items to be inspected by the DSV include:

- A trip tank complete with a mechanically operated level indicator, visible from the driller's position.
- A fully functional Crown-o-Matic or equivalent safety brake installed on the draw-works.
- Martin Decker or equivalent weight indicator.
- BOP's with two ram type and one annular preventer.

### **3.3.3.3 Monitoring Equipment**

The minimum level of rig monitoring equipment required:

- Active and trip tanks volume.
- Return flow.
- Total gas at header box. (Mudlogger)
- H<sub>2</sub>S at shakers, BOP's and drillfloor (Mudlogger)
- Weight on bit.
- Hookload.
- Rotary torque (Relative torque on mechanical rigs).
- Rotary speed.
- Standpipe pressure.
- Casing pressure.
- ROP.
- SPM for each pump.
- Rig air pressure.
- Accumulator unit pressures.
- 6 channel pen recorder (geolograph) or better.

It is the responsibility of the DSV to ensure that the above list of monitoring equipment is available and in working order.

### **3.3.3.4 Downhole Equipment**

The provision of downhole drilling equipment shall be detailed by the DM in the relevant contracts between the Company, the Drilling Contractor and the relevant Service Companies. The following information should be included:

- The dimension of any contractor item run into the hole shall be recorded on the BHA sheet. The Drilling Contractor shall be responsible for providing fishing tools for all contractor supplied equipment.
- Only drill pipe with smooth hardbanding or no hardbanding shall be used when rotating inside casing.
- Only "fit for purpose" drill pipe shall be used (i.e. as defined in the latest edition of API RP7G).
- Drill pipe and BHA shall be NDT inspected every six months. Copies of the inspection records shall be kept on the rig.
- Drilling jars must be used when drilling. The normal procedure shall be to position the jars two or three drill collars from the top of the DC section while drilling vertical wells.
- All roller reamers shall be of the sealed bearing type.
- Either Integral Blade or sleeve type stabilisers will be run. Stabilisers will be 1/64" undergauge when new. Stabilisers will be gauged on each trip and those more than 3/16" undergauge should be laid out.



API RP7G (specifications for Drill Pipe)

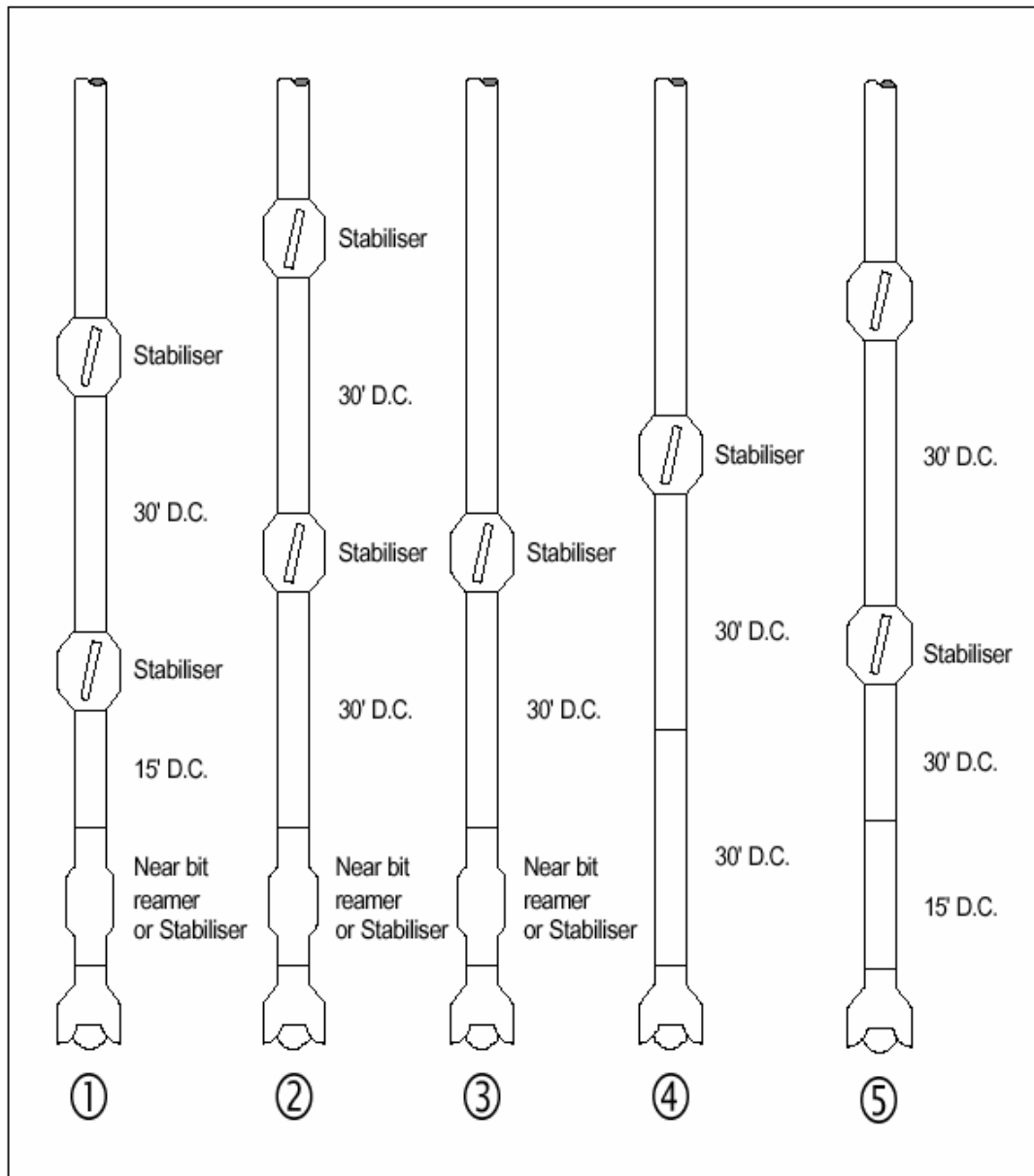
### **3.3.3.5 Typical Bottomhole Assemblies**

Each generalised configuration of bottomhole assembly (BHA) shown below demonstrates a typical directional tendency while drilling.



The effect of each configuration depends on a number of variables, including formation hardness and bed dip, bit type, stabiliser type and diameter, hole size and drilling parameters such as weight on bit and rotary speed.

Stabiliser wear in abrasive formations has a significant effect on directional control, where sleeve stabilisers may be preferable to integral blade types. The general directional tendencies due to stabiliser placement for drilling main hole are described in the following diagram and table.



**Figure 1. Vertical Well Generalised BHA Configurations**

Bottom Hole Assembly Type	Configuration and Directional Tendency
Assembly 1	The near-bit stabiliser or reamer is the primary angle building and hold tool. The stiffer the BHA near the bit, the less likelihood of bit deviation (more contact area gives a higher degree of control). This <b>"locked"</b> , <b>"stiff"</b> or <b>"packed"</b> assembly is commonly used to hold angle in vertical and low angle wells; it will drop angle at moderate to high inclinations. The second stabiliser may be moved upward 15 - 20' to ease the degree of stiffness if required.
Assembly 2	This assembly may be more effective in certain areas than Assembly 1 due to the combination of variables listed, but represents a <b>reduced stiffness</b> and therefore a medium or more neutral angle-holding configuration for moderate inclinations. If the distance between the near-bit and next stabiliser is increased towards 45', the assembly may start to demonstrate gentle building tendencies. Also, the diameter of the stabiliser will influence the tendency to either build or drop.
Assembly 3	This configuration will hold angle at higher inclinations, and may also exhibit stronger building tendencies due to the removal of the second stabiliser and resultant reduction in stiffness.
Assembly 4	This configuration is a classic <b>"pendulum"</b> , or dropping assembly, with the stabiliser placed as far as possible above the bit without causing wall contact with the pipe. This spacing is typically 60'. However if a low bit weight is used in a low-angle hole, greater drop-off may be achieved with the stabiliser placed further than 60' from the bit. The behaviour is less predictable unless low bit weights are used.
Assembly 5	This configuration is a <b>modified "pendulum"</b> assembly with stabilisers positioned 45' and 75' above the bit. Although the dropping tendency is reduced in comparison to the 60/90' pendulum assembly (described above), the modified assembly allows higher bit weights to be used without compromising directional control. The modified pendulum assembly may be of particular use while drilling vertical wells.

**Table 3. Vertical Wells Bottom Hole Assembly Configurations.**

### **3.3.4 Pressure Control Equipment**

Pressure control equipment shall be supplied and maintained in accordance with Chapter 10 of this Manual. It is the responsibility of the DSV to ensure that all equipment is in full compliance with the specifications detailed in the relevant contracts between the Company and the Drilling Contractor. A summary of the main requirements are listed below:

- Only original equipment spare parts shall be used in the BOP/Koomey (accumulator) system
- Pressure control equipment shall be function tested every day except the blind rams which shall be tested on every trip and pressure tested every 14 days, or on the closest trip to this date.
- As a minimum the 'Poorboy' mud gas separator should have a minimum 8" vent line and a mud seal of at least 1.5 m (5').
- A full bore kelly cock shall be installed at the base of the kelly at all times. A ball type stabbing valve, with connections or a cross-over to suit the workstring, shall be available on the rig floor at all times, together with an operating handle for the valve.
- During drilling, the outer side outlets of the wellhead exposed to the live annulus shall have manual or hydraulically operated side outlet valves.
- A wellhead wear bushing must be installed in the wellhead during all drilling and logging operations.
- A float must be used while drilling production hole sections.

The following safety equipment shall be on the drilling unit at all times and shall be fully functional:

- Full opening inside BOP.
- Crossovers to allow installation of above into any type of connection used in the drill string or tubing string.

### **3.3.5 Kick Detection and Well Monitoring Equipment**

Kick detection and well monitoring equipment shall be supplied and maintained in accordance with the requirements detailed in Chapter 10.

It is the responsibility of the Drilling Contractor to ensure that the following minimum kick detection equipment is available, tested and fully operational:

- Flowline monitor.
- Active pit volume monitors.
- Gas detection at header box (supplied by the mudlogging contractor).
- ROP recorder.
- Trip tank with a system for accurately monitoring returns during tripping.

The Mudlogging Contractor shall ensure that all gas detection equipment (including H2S detectors) and alarms are functioning properly. The Drilling Contractor shall ensure continuous monitoring and recording (if applicable) of the following parameters is available on the drilling site for all wells:

- Active pit volume.
- Weight on bit and hook load.
- Rotary torque and speed (not installed on every rig).
- Standpipe pressure and choke pressure.
- Rate of penetration.
- Mud pump SPM.
- Rig air pressure
- Koomey (accumulator) unit pressures

Although kick detection and well monitoring equipment is supplied and maintained by the Drilling Contractor, it is the responsibility of the DSV to ensure that regular equipment checks are maintained. All equipment shall be audited on a regular basis during safety visits by the DE / DS.

Drilling of the main hole section shall not commence without written approval of the DM if any of the above equipment is inoperable.

### **3.4 GENERAL OPERATIONAL PRACTICES**

#### **3.4.1 General Practices**

The following general practices shall be adhered to during drilling operations. It is the responsibility of the DSV to ensure conformance.

##### **3.4.1.1 Pre-spud Preparations**

The DSV shall ensure that the drilling crew are familiar with Company Well Control Procedures detailed in Chapter 10 and the following are available:

- Adequate mud weighting materials are on site or readily available in sufficient quantities to support the drilling operation.
- All fishing tools relevant to the hole interval are available at the wellsite. Drilling Contractor fishing tools shall be available for all Contractor supplied downhole tools as per the relevant contract.
- The ID of all downhole equipment shall be checked for free passage of a free point indicator tool and survey instrument fishing tools.
- All BOP equipment and drillstring well control equipment.
- The DSV shall also inspect the rig and fill out the Pre Spud Checklist prior to the well being spudded.

##### **3.4.1.2 Drilling Operations**

The DSV is responsible for ensuring that all relevant Drilling Contractor and service personnel are aware of the GSLM General Drilling Practices during all hole sections. The General Drilling Practices are detailed below:

- Flow checks shall be performed in accordance with the requirements tabulated in Section 3.4.2. A minimum of one bottoms up shall be circulated prior to any trip out of the hole or after completion of any well kills.
- The trip tank shall be used on all trips out of the hole.
- Trip sheets shall be used in all trips in and out of the hole.
- Slow Circulating Rates (SCR) shall be performed in accordance with the requirements tabulated in Section 3.4.2.
- Drill-off tests may be conducted on each new bit run for optimum WOB
- Kill sheets shall be completed as per the Well Control section.

### 3.4.2 Primary Well Control

Detailed procedures for the conduct of well control operations are contained in Chapter 10. The table and text below provides the standard guidelines and practices which must be observed during drilling operations to maintain primary well control.

Operation	Guidelines
Slow Circulation Rates (SCR)	<p><u>Must</u> be performed as a minimum</p> <ul style="list-style-type: none"> <li>• Once per tour.</li> <li>• After every bit change</li> <li>• .After every BHA change.</li> <li>• After significant drilling fluid density or rheology changes.</li> <li>• After any work on mud pumps or surface lines</li> </ul>
Flow checks	<p><u>Should</u> be considered in any of the following circumstances.</p> <ul style="list-style-type: none"> <li>• Pit gain or loss.</li> <li>• Significant drilling break.</li> <li>• At start of trip out, after 10 stands, with bit at shoe and at top of BHA.Drilling break.</li> <li>• Variation in pump pressure or speed.</li> <li>• Gas, oil or salt water contamination (chloride increase).</li> <li>• Erratic rotary torque.</li> <li>• Lost circulation.</li> <li>• Variation in observed string weight.</li> </ul>

**Table 4. Well Control Guidelines**

The following guidelines are also applicable to well control:

- Additional checks must be performed whenever there is any concern about well control.
- Kick drills shall be carried out according to procedures defined in Chapter 10.
- Time spent with the pipe out of the hole shall be minimised.
- A minimum of one complete circulation shall be performed after completing all well kills.
- Casing shall be pressure tested to a maximum of 80% of the rated burst pressure of the weakest casing when bumping the plug. If the plug dose not bump the casing must be pressure tested prior to drilling out the shoe.
- Leak-off tests shall be performed after drilling 3 m of new formation at all casing shoes, unless otherwise specified (See Section 9.7).

### 3.4.3 Diverter

Incidences of shallow gas have been reported in Tasmania so the use of a diverter while drilling surface hole is required.

### 3.4.4 BHA Handling

BHA handling shall be performed according to the guidelines in the table below.

BHA and Connections	Guidelines
Stabilisers	Serial numbers and rotating hours for each stabiliser must be recorded on the morning report. Make up or break down stabilisers in the drill collar string using a winch line or maintain vertical using a mechanical support (e.g. pin in rotary table, clamp support hooked around drill collar in rotary). Manual support of the stabiliser without mechanical back up while engaging or disengaging the threads is not permitted. All stabilisers shall be gauged on each trip and consideration should be given to laying out all stabilisers more than 1/8" undergauge.
Chicksan Connection	Such connections shall not be made up to a downhole string component before the component is incorporated in the string and lowered through the rotary table to refusal or safe working height. In the event that circumstances dictate otherwise, the chicksan connection shall be safeguarded by attaching a safety line to prevent free fall.
Threaded Connection	Any threaded connection carried on top of a string suspended above safe working height and not made up to the recommended torque, shall be marked with chalk and continuously monitored when rotating (part of) that string.
New Threads	New threads which have been cut shall be broken-in carefully when making up for the first time (i.e. Make/break/make each joint).

**Table 5. BHA Handling Guidelines**

Rotating the drill string below the rotary to make up pipe once the BHA is run shall be avoided.

Backing the rotary into a string to make up a connection is poor practice and can result in a dropped string or an accident due to damaged threads. This practice is not permitted.

All BHA components shall be measured for OD, ID, length and fishing neck sizes. A diagram of each BHA shall be submitted by the Drilling Contractor to the DSV. The serial numbers and rotating hours of all roller reamers, stabilisers, NMDC, jars etc. shall be recorded on the morning report.

### 3.4.5 Specific Drilling Procedures

Specific drilling procedures are provided in detail in each Drilling Program to ensure that wells are drilled:

- Safely.
- In line with good oilfield practice.
- In accordance with GSLM's policies, standards and guidelines.

The essential items to observe while drilling a well are contained in this chapter of the Drilling Operations Manual, the Generic Drilling Program and, where relevant, are referenced elsewhere. All critical items shall be included in each Drilling Program to ensure that wells are drilled safely and in line with good oilfield practice, as well as in accordance with the GSLM's policies, standards and guidelines given in this Manual.

### 3.4.6 Local Hole Problems

Hole problems may be encountered during drilling operations in Tasmania. The problems and solutions are tabulated below.

Cause	Problem	Solution
Dioritic sills (possibly fractured)	Mechanical sticking.  Very low ROP.  Lost circulation	<ul style="list-style-type: none"> <li>• Drill with slick BHA</li> <li>• Work pipe frequently</li> <li>• Good hole cleaning</li> <li>• Drill bits (eg impreg on motor)</li> <li>• Air drill</li> <li>• Hammer drill</li> <li>• Low mud weights.</li> <li>• LCM</li> </ul>
Low pressure and permeable water-bearing sands at shallow depths	Hole instability	<ul style="list-style-type: none"> <li>• Low mud weights and effective hole cleaning are essential to minimise losses and washouts</li> </ul>
Poor wall filtercake	Tight hole	<ul style="list-style-type: none"> <li>• Low mud weight combined with optimal rheology, fluid loss and hole cleaning should minimise the problem</li> </ul>
Sloughing at deeper depths	Hole instability	<ul style="list-style-type: none"> <li>• Increasing the mud weight, typically up to 9.6 ppg. A relatively in-gauge hole is required to provide a packer seat just above the pay zone.</li> </ul>
Fragile coal seams	Packing-off hole	<ul style="list-style-type: none"> <li>• Avoid packing off hole when pulling the BHA and swabbing the hole by pulling slowly through known coal seams.</li> <li>• Cuttings returned to surface should be closely monitored and compared to the ROP. Inconsistencies may indicate a sloughing coal seam higher in the hole</li> <li>• Drilling coal generally requires frequent, short wiper trips to ensure that the hole is kept clear of cuttings and to avoid the risk of stuck pipe.</li> <li>• For thick coal seams drill no more than 5' before picking up and working a full single 2-3 times while maintaining full pump rate.</li> </ul>

**Table 6. Solutions to Hole Problems.**

It is the responsibility of the DSV to ensure that the Drilling Contractor is fully aware of the potential problems.

### 3.4.7 Tripping Practices

- A minimum of bottoms up shall be circulated up prior to any trip out of the hole. In high angle wells this should be increased to at least 2x times bottoms up (at drilling circulating rate) or until the shakers are free of cuttings.
- A trip sheet shall be filled out by the Driller and Mud Logging Contractor for each trip in/out of the hole. All variances from expected fill/return shall be investigated. The trip tank shall be used on all trips.
- The time spent with the pipe out of the hole shall be minimised wherever possible. Operations such as routine BOP testing, repairs and slipping and cutting of the drill-line shall be performed with pipe at the casing shoe whenever possible.
- Check trips may be required in the following cases:
  - During logging when hole conditions deteriorate and become sticky.

- Before RFT/MDT tools are run if previous runs indicate poor or deteriorating hole conditions. If required this wiper trip can be made one logging run before the MDT.
- Before running casing if hole conditions during logging indicate that this is necessary.

### Notes

- i. In all of the above cases, the BHA must be as short as possible.
  - ii. In upper hole sections, the BHA should include full gauge stabilisers and be at least equal in stiffness to the casing string if required.
  - iii. Monel DCs shall not normally be run in check trips.
- e) When the condition of the hole is unknown due to a major change in parameters, a short trip shall be made. The procedure is as follows:
1. After circulating bottoms up flow check for 15 minutes. Slowly pull 10-15 stands while using the trip tank to ensure that the hole is taking the correct quantity of mud. Check for flow. Run back to bottom, check for fill and check for flow again.
  2. Circulate bottoms up and condition the mud. Check the mud returns for gas and salinity. Increase the mud weight if there are signs of an influx.
- f) Slow trip speeds while running drill collars (and BHA's) past coal seams is essential to the stability of the seams.

Tripping procedures to be posted in the doghouse are shown in Appendix 1.

### Wiper Trips

As a general guide wiper trips may be run as follows:

- Once every 24 hrs or 450 m (1,500'). These trips will generally be made back to the depth of the previous wiper trip, the start of the bit run or the previous casing shoe whichever is deepest.
- Wiper trip back to surface prior to POOH to run surface casing.
- Wiper trip back to old hole when POOH to run intermediate casing, logs, DST's cut cores etc.

### Standard Tripping Procedures.

1. Fill the trip tank to the highest recording level using mud from the suction tank. Do not fill the tank by diverting returns - this will allow cuttings to settle. Record the initial volume in the tank.
2. If required, in top hole only:
  - While circulating prior to tripping, prepare a heavy slug (normally 1 ppg heavier than mud weight in use) in the pill tank..  
The volume of heavy slug required is calculated as follows:  
$$\text{Slug Volume} = (\text{Drop length} \times \text{pipe capacity} \times \text{Mud wt}) / (\text{Slug wt} - \text{Mud wt})$$
3. Prepare the trip sheet. Shut down the pump and flow check. If the hole is stable; (in top hole only, pump the slug) break out and set back the kelly.
4. When the levels have equalised and annulus flow has stopped, switch the returns to the trip tank.



5. Pull the first 5 - 10 stands without continuously filling the hole to allow the level to be visually monitored for piston type swabbing. Wiper rubbers are not to be installed until at least these 5 - 10 stands have been pulled without indication of swabbing.

Remember that bottom hole pressure is reduced by the swab pressure plus the loss of hydrostatic head due to the lower fluid level in the annulus.

6. Start the trip tank pump and run continuously while pulling the remaining pipe.
7. If the hole does not take the full calculated fill, flow check. If the well is flowing the BOP must be closed immediately and the pipe stripped back to bottom if possible.

**Under no circumstances must an attempt be made to 'outrun the kick' by running quickly back to bottom without closing the BOP. The situation will deteriorate rapidly and a blow out is almost inevitable.**

If the well is not flowing then the reason for the discrepancy must be determined before pulling any further pipe. If there is any doubt, the pipe should be run back to bottom and the hole circulated. Monitor returns while running in.

8. When the trip tank has to be refilled, stop the trip and wait for the tank to fill. Do not trip and fill simultaneously. Take the opportunity to flow check the hole.
9. The crew should develop the habit of watching the hole level while tripping.
10. Perform a flow check with the bit at the casing shoe, and prior to pulling the collars across the BOP rams.
11. If tight hole is experienced, the annulus level must be closely monitored for piston type swabbing. When working the tight hole, work up cautiously ensuring that the pipe can always be run back down. Be aware that if an influx occurs in a tight hole situation, any flow will tend to be directed inside the drill pipe. If the flow occurs with the pipe high in the mast, it may very quickly become very difficult to install the stab valve.

If the tight hole cannot be safely worked through, do not hesitate to pick up the kelly and circulate/ream the hole.

12. While running in the hole the procedure should be reversed so that the volume of mud returns are monitored.
13. The drilling line must not be slipped with pipe out of the hole or with collars across the BOP. The pipe should be run back to the shoe and the stab valve installed.
14. Trip sheets must be retained and filed.

### 3.5 PREVENTION OF STUCK PIPE

The following guidelines outline key requirements (during well planning and at the wellsite) to minimise the incidence of stuck pipe.

#### 3.5.1 General Preventative Measures

The DM is responsible for identifying all stuck pipe preventative measures during planning and documenting them in the Drilling Program. The DSV is responsible for ensuring that the stuck pipe preventative measures tabulated below are performed by the Drilling Contractor at the wellsite.

Activity	Prevention
Planning	<ul style="list-style-type: none"> <li>• The Drilling Programme should include identification of potentially troublesome formations and procedures for their prevention i.e. frequency of wiper trips, etc.</li> <li>• Careful consideration must be given to proper design and selection of BHA's and their components.</li> <li>• The amount of open hole time for each section of the hole must be kept to a minimum.</li> <li>• The drilling fluid system must be properly designed.</li> <li>• Troublesome formations must be cased-off.</li> </ul>
Wellsite	<ul style="list-style-type: none"> <li>• Allow sufficient time to properly condition the drilling fluid.</li> <li>• In open hole, keep the drill string moving whenever possible.</li> <li>• Time spent in open hole shall be minimised.</li> <li>• Ensure that the drillers have been told what action to take in the event of tight hole or other problems.</li> <li>• At the first sign of tight hole, the Toolpusher and DSV shall be called to the rig floor.</li> <li>• Exercise extreme caution when tripping in open hole.</li> <li>• Never try to force the string through a tight spot.</li> <li>• Never pull more overpull than the weight of the drill collars as this will almost always result in the string becoming stuck.</li> <li>• The last three joints (at least) should always be washed to bottom.</li> <li>• Always clean the hole before tripping.</li> <li>• Regular wiper trips must be made, either at pre-determined intervals or as hole conditions dictate.</li> <li>• The shale shakers must be monitored regularly by the DSV as well as by the Drilling Fluids Engineer</li> <li>• Utilise all solids control equipment to minimise the amount of drilled solids in the mud.</li> </ul>

**Table 7. General Preventative Measures against Stuck Pipe.**

#### 3.5.2 Prevention of Differential Sticking

The DM is responsible for identifying in the Drilling Program the potential for all likely incidents of differential sticking whilst the DSV is responsible for ensuring that the preventative measures tabulated below are performed by the Drilling Contractor at the wellsite.

Activity	Prevention
Planning	<ul style="list-style-type: none"> <li>Highlight in the Drilling Program permeable formations that may lead to differential sticking.</li> <li>Estimate the problem formation pressure using the best and most current offset data available.</li> <li>Any requests to run RFTs or MDTs should be considered carefully as they may increase the possibility of differential sticking.</li> <li>Careful consideration of the number of pad type logging tools employed in holes where differential pressures are known to be high.</li> <li>Lubricants can reduce the high coefficient of friction between the wellbore and the drillpipe.</li> <li>Reduce the filter cake thickness by the addition of "bridging" material to the drilling fluid.</li> <li>Shaker screens must be selected to prevent or minimise a drilled solids build-up, as low gravity solids result in thick and sticky filter cakes.</li> <li>HTHP fluid loss must be run on the drilling fluid when drilling in areas of known differential sticking, regardless of the bottom hole temperature.</li> <li>Do not program any non-essential surveys, as they are a high risk operation.</li> </ul>
Wellsite	<ul style="list-style-type: none"> <li>Continuously monitor the differential pressure across permeable formations as accurately as possible. Trends of overpull on connections, trip gas levels, and connection gas levels shall be followed to anticipate changing pressures.</li> <li>Keep differential pressures across permeable formations to a minimum by keeping the mud weight at the lowest safe level.</li> <li>Maintain drilling fluid parameters within the specifications of the Drilling Programme.</li> <li>Stabilisation and spiral drill collars should be used to centralise and minimise wall contact.</li> <li>Keep the pipe moving at all times. Reciprocate if possible. Do not leave the pipe static in high risk areas.</li> <li>Spot LCM pills across depleted zones while drilling and prior to evaluation.</li> <li>Utilise all solids control equipment to minimise the amount of drilled solids in the mud.</li> <li>When running wireline surveys consider racking back the kelly and work the string with the elevators.</li> </ul>

**Table 8. Preventative Measures against Differential Sticking.**

### 3.5.3 Inadequate Hole Cleaning

The DM is responsible for preparing a Drilling Program that minimises the potential for inadequate hole cleaning and stuck pipe. The DSV is responsible for ensuring that the preventative measures tabulated below are performed by the Drilling Contractor at the wellsite.

Activity	Prevention
Planning	<ul style="list-style-type: none"> <li>Circulation rates need to be kept as high as possible in large diameter hole sections.</li> <li>Include recommended minimum circulation rates in the Drilling Fluids Program.</li> <li>Hole angles between 50o and 60o are the most difficult to clean. The Drilling Program for wells with these angles shall highlight this potential.</li> <li>A study of offset well data may indicate signs of over-gauge hole that may need to be included in minimum flow rate calculations.</li> </ul>
Wellsite	<ul style="list-style-type: none"> <li>The hole shall be circulated clean prior to the start of a trip. Rotation and reciprocation of the pipe will improve cleaning.</li> <li>Special tripping and circulating procedures may be necessary in wells with cutting beds and wells with severe over-gauge sections, such as pumping and backreaming out.</li> <li>Do not let the flow rate drop below the minimum required to effectively clean the hole.</li> <li>Do not continue to drill in anticipation of cleaning the hole at a later stage - that may be too late to avoid getting stuck.</li> <li>Utilise all solids control equipment to minimise the amount of drilled solids in the mud.</li> </ul>

**Table 9. Hole cleaning - Preventative Measures against Stuck Pipe**

The following indicators may identify hole cleaning problems:

- ☑ Excessive overpull on connections and trips.
- ☑ Reduced overpull when pumping.
- ☑ Excessive fill after trips.
- ☑ Erratic and increasing torque while drilling.
- ☑ Lack of cuttings over shakers.

Appropriate action must be initiated when any of the above indicators are encountered while drilling.

### 3.5.4 Formation Instability

The DM is responsible for highlighting in the Drilling Program all likely zones of formation instability using offset well data. The DSV is responsible for ensuring that the preventative measures tabulated below are performed by the Drilling Contractor at the wellsite.

Activity	Prevention
Planning	<ul style="list-style-type: none"> <li>Ensure that the drilling fluid formulation is designed to cope with gumbos and swelling shales where they are indicated.</li> </ul>
Wellsite	<ul style="list-style-type: none"> <li>Trip cautiously through swelling formations.</li> <li>In tight hole, ream each single. When using a top drive, pick up and ream midway through each stand. If hole conditions are severe, more frequent reaming may be required.</li> <li>After pulling into a tight spot, run back into gauge hole and circulate before back reaming out.</li> <li>Sections of the hole found to be tight on the way out of the hole shall always be reamed on the trip back in.</li> <li>Wiper trips must be conducted regularly as defined in the Drilling Program with additional trips made as required. Consideration of the stuck pipe risks must be made before dropping a single shot survey in tight hole situations.</li> <li>No unnecessary time shall be spent in open hole.</li> </ul>

**Table 10. Prevention of Stuck Pipe due to Formation Instability.**

### 3.5.5 Key Seating

The DM is responsible for highlighting in the Drilling Program the possibility of key seating. The DSV is responsible for ensuring that the preventative measures tabulated below are performed by the Drilling Contractor at the wellsite.

Activity	Prevention
Planning	<ul style="list-style-type: none"> <li>Offset well data shall be reviewed for incidents of key seating and any occurrences shall be noted in the Drilling Program.</li> <li>Ensure that a string reamer or key seat wiper (preferred) is available on the rig for each relevant hole size where key seating is considered to be a potential problem.</li> </ul>
Wellsite	<ul style="list-style-type: none"> <li>Ream any severe doglegs to prevent key seats developing.</li> <li>Use a string reamer with a diameter larger than the drill pipe tool joint and smaller than the drill collars in the drill pipe to wipe the build section or Dog Leg if a key seat is expected or suspected.</li> </ul>

**Table 11. Prevention of Key Seating.**

### 3.5.6 Bottom Hole Assembly Changes

All BHA changes shall be identified in the Drilling Program by the DM. The DSV is responsible for ensuring that the preventative measures tabulated below are performed by the Drilling Contractor at the wellsite.

Activity	Prevention
Planning	<ul style="list-style-type: none"> <li>Do not plan a stiff assembly to follow a flexible BHA without flagging in the Drilling Program that care must be taken when tripping in.</li> </ul>
Wellsite	<ul style="list-style-type: none"> <li>Bits and stabilisers shall always be gauged after each trip.</li> <li>If the bit is pulled undergauge the whole of the section drilled by the previous bit may require reaming.</li> <li>Do not trip a BHA of increased stiffness into the hole rapidly. Expect to have to ream.</li> <li>If the hole is suspected to be undergauge, extreme caution must be applied when tripping into the hole.</li> </ul>

**Table 12. General Consideration for BHAs in Preventing Stuck Pipe.**

### 3.6 PREVENTION OF LOST CIRCULATION

The following guidelines outline the key requirements to prevent or reduce lost circulation while drilling. It is the responsibility of the Drilling Contractor to recognise any lost circulation and immediately inform the DSV of its occurrence.

#### 3.6.1 Procedures to Minimise Losses

There are five procedures that may be performed by the Drilling Contractor to minimise losses. These are tabulated below.

Control to Minimise Loss	Procedure
Mud weight	Ensure that the mud density is not allowed to increase due to build up of solids, by maintaining and fully utilising an efficient solids control system, and by dilution where necessary.
Drilling fluid properties	Excessive gel strengths and viscosity, frequently due to an unacceptable increase in drilled solids, may result in seepage losses as a result of downhole circulating pressures.
Overloading annulus	The drilling rate must be controlled to ensure that the annulus is adequately cleaned and the drilling fluid maintained with an adequate carrying capacity to clean the annulus. Solids control equipment must be fully utilised to maximise removal of solids. Failure to adequately clean the hole may result in the formation of annular "mud rings", causing partial or total impedance to circulation.
Reduce Pump pressure	Pump pressure can be reduced by reducing flow rate, increasing nozzle size or changing mud properties
Pressure surges	Run in hole slowly and steadily to avoid surging the well, especially in the smaller boreholes.

**Table 13 Procedures for Minimising Losses.**

#### 3.6.2 Lost Circulation Pills

Lost circulation ranges from seepage losses to complete loss of returns.

The recommended lost circulation material (LCM) that may be used across reservoirs and other formations without causing formation damage is Enerseal super fine or its equivalent, Sandseal. Quantities shall be determined on site, and returns shall be carefully monitored. Enerseal can be used either in concentrated slugs or as a general drilling fluid treatment as required.

Where seepage losses increase to more than 20 bbls/hour, a LCM pill may be required to provide more effective prevention than can be achieved by circulating LCM in the drilling fluid.

The generic procedure for the preparation and application of a LCM pill is as follows:

1. Mix a LCM pill in the slugging pit using the recommended LCM material (or alternative approved material where applicable). The actual concentration will be dependent upon the magnitude of the losses and the size of the jets in the drilling bit.
2. Spot the LCM pill on bottom.
3. Pull the bit above the loss zone and the top of the LCM pill.
4. Observe the well for one hour, keeping the hole full as required.
5. Gradually commence circulation and attempt to regain full returns.

### **3.7.1 Introduction**

The implementation of the Drilling Program is carried out by contractors and verified by the DSV. The DSV should ensure that the program is followed to control and minimise risk and to make sure that the ongoing program is safe, efficient and effective.

### **3.7.2 Activities**

#### **2.7.2.1 Prepare and Send Daily Drilling Report to the GSLM Drilling Manager**

The DSV shall complete the DDR after receiving the IADC report from the drilling contractor and operational reports from other contractors..

#### **3.7.2.2 Morning Call**

The DSV will call the DM each morning to discuss and incidents, logistical requirements and past and future operations. Based on this the DSV and DM shall address the safety, operational or logistics requirements.

#### **3.7.2.5 Issue Work Instructions**

Where possible all work instructions should be in writing and given to the contractors rig manager, who shall discuss them with the DSV before issuing them to the driller. The DSV shall issue instructions to third party contractors as required..

#### **3.7.2.6 Afternoon Report**

The afternoon report shall be a short summary, unless non standard operations are underway, following the same structure as the Morning Report

#### **3.7.2.7 Verify Rig Operations and Prepare Non-conformance Reports**

The DSV shall, on an ongoing basis, verify that work is being carried out in accordance with the Drilling Program, the DOM and HSWE requirements. He shall discuss the work as necessary with the GSLM DM and the rig TP.

Where a serious non-conformance is discovered, the DSV shall complete an incident report form detailing the action taken. The purpose of this is to initiate analysis and help ensure that the non-conformance is not repeated.

#### **3.7.2.8 Analyse Non-conformance**

All incident report forms shall be sent to the DM who shall investigate the report, carry out further analysis and discuss the report as necessary.

### 3.8 REPORTS AND REPORTING

Effective reporting is essential for a safe and efficient drilling operation. The objective is to keep the reports to an effective minimum and to simplify reporting lines wherever possible.

#### 3.8.1 Reporting Relationships

- The DSV reports routinely to management via the DM assigned to the well.
- The DSV shall consult with the DM in the event of incidents occurring outside the scope of the drilling program (e.g. excessive tight hole, well control issues etc.).

**Note:** Drilling instructions shall ONLY be relayed to the rig via the DM

#### 3.8.2 Daily Drilling Report

The morning report shall be transmitted to the DM by 0700 latest.

EXPLANATION OF TERMS IN DDR	
Term	Explanation
Date	The report is dated for the day of the report (day previous to dispatch).
Addressee	DM
Depth	Current depth at 0600, in feet or meters as specified in Drilling Program
Progress	Progress for previous 24 hours.
Day +/- Curve	Report days ahead (+) or behind (-) the TVD curve as in the Detailed Drilling Program.
Formation Tops	List the type and depth of each formation encountered during the last 24 hours.
Activity Report	Ensure that phase class and operating codes are correct because the software analyses the times by these classifications. Report times to the nearest 30 minutes.
Comments	It is important that the remarks / observation and solution / recommendation section is completed for any and all non-routine occurrences.
Mud Properties	Complete fully and in detail ensuring that the data matches the latest mud check.
Bit Data	Complete in full, note that the new IADC classification is to be used for dull grading.
BHA	Complete in full for the BHA in use. Include serial numbers and rotating hours for all NBRR, Stabilisers, Jars, NMDC, Motors etc.
Bulk Stocks	Complete in full for the stocks at 0600.
Surveys	List the tool type in "Last Tool Type" (i.e. Totco, MSS or MMS).

**Table 15. Explanation of Terms in DDR**



### **3.8.3 Other Reports**

#### **Casing and Cementing**

- The following reports shall be E-mailed to the DM.
  - I. Casing Tubing Tally – Sent to DM for checking and verification prior to the casing being run.
  - II. Casing & Cement Report – Sent to the DM within 24 hours of the cement job.

#### **Leak off Test/Formation Integrity Test**

- Complete as per Chapter 9.7 and E-mailed to the DM with the next morning report.

#### **BOP Test Sheet**

- Complete for each BOP test.  
Ensure that all sections are accurate and E-mail to the DM.

#### **Well Control Kill Sheet**

- The pre-recorded data shall be completed at minimum everyday while drilling below the surface casing.
- The form is retained on the rig and may be audited by GSLM and/or regulatory personnel.

#### **Daily Drilling Costs**

- The DM shall complete the relevant sections of the daily cost report
- 

#### **End of Well Reports**

- The following reports shall be completed at the end of the well and faxed to the DS/DE within 24 hours of rig release.
  - (i) Wellhead Installation Report for Conventional wells
  - (ii) Well Abandonment Report - if applicable
  - (iii) End of Well Equipment Report
  - (iv) Rental equipment used on well

#### **End of Hitch Report**

- To be completed by the DSV every hitch
- Should be E-mailed to the DM prior to leaving rig.

# TRIPPING PROCEDURES

(To be displayed in Doghouse)

## Tripping Practices

- a) A minimum of one complete circulation shall be performed prior to any trip out of the hole. When circulating to condition mud, a circulating rate of 50 - 75% of the normal circulating rate shall be used.
- b) A trip sheet shall be filled out by the Driller and Mud Logging Contractor for each trip in/out of the hole. All variances from expected fill/return shall be investigated. The trip tank shall be used on all trips.
- c) The time spent with the pipe out of the hole shall be minimised wherever possible. Operations such as routine BOP testing (except blind rams), repairs and slipping and cutting of the drill-line shall be performed with pipe at the casing shoe whenever possible.
- d) Check trips may be required in the following cases:
  - 1. During logging when hole conditions deteriorate and become sticky.
  - 2. Before RFT/MDT tools are run (If supercharged formations are possible, this wiper trip may be made 1 logging run prior to the MDT/RFT run).
  - 3. Before running casing, if hole indications during logging indicate that this is necessary.

### Notes:

- i. In all of the above cases, the BHA must be as short as possible.
  - ii. In upper hole sections, the BHA should include full gauge stabilisers and be at least equal in stiffness to the casing string if required.
  - iii. Monel DCs shall not normally be run in check trips
- e) When the condition of the hole is unknown due to a major change in parameters, a short trip shall be made. The procedure is as follows:
  - 1. After circulating bottoms up flow check for 15 minutes. Slowly pull 10-15 stands while using the trip tank to ensure that the hole is taking the correct quantity of mud. Check for flow. Run back to bottom, check for fill and check for flow again.
  - 2. Circulate bottoms up and condition the mud. Check return mud weight and for signs of entrained gas or dilution. Increase the mud weight if there are signs of an influx.
- f) Slow trip speeds while running drill collars (and BHAs) past coal seams is essential to the stability of the seams.
- g) The majority of the world's blowouts occur while tripping in normally pressured areas. The main reasons are swabbing in a kick, failure to keep the hole full, or breaking down the formation due to excessive trip speed.

The term 'swabbing' on a rig generally refers to the bit and/or stabilisers acting as a swab or piston and actually lifting the full mud column. This typically occurs with tight or sticky hole when the bit, stabilisers, or collars become packed with wallcake leaving a very restricted passage for the mud. This situation is readily noticeable as the mud level in the annulus tends to rise with the pipe rather than fall. In addition, since the drillstring is picking up all or a portion of the weight of the mud column above, the string weight shows an increase.

Swab and surge pressures actually occur every time the pipe is moved as a result of the viscous drag of the mud. The factors affecting the magnitude of these pressures for a given hole/pipe combination are mud rheology and pipe speed.

The swab situation is more insidious since the influx may occur in very small increments and may not become evident until the influx has migrated almost to surface after a period of hours. By the time this happens, the pipe is a long way off bottom and well control becomes extremely difficult and may become impossible. There are many instances of the drill string being blown out of the hole in these situations.

It is a fundamental fact of life on the wellsite that the hole must be kept full at all times. All too often complacency creeps into operations, corners start to be cut and drillers don't want to 'waste time' filling in trip sheets.

Hole filling should be a continuous operation performed with the trip tank, NOT WITH THE MUD PUMP. In order to fill the hole on a continuous basis a heavy slug must be pumped to allow the pipe to be pulled dry. Pulling wet pipe slows the operation and the loss of mud can make volume accounting difficult.

A trip sheet **must** be filled out for every trip including short wiper trips.

To minimise the risk of influxes occurring and to maximise the speed of detection when they do occur, it is imperative that safe trip procedures are strictly followed.

As always the golden rule is "if in doubt, stop and check". Do not blunder along into a disaster.

When tripping, ensure that the pipe is not set too high in the slips. Setting the pipe high can result in bending the pipe in the slip area.

The maximum height to avoid bending can be calculated. The procedure is shown below for two cases. Case 1 is for the make-up and break-out tongs at 90 degrees to each other; Case 2 is for the make-up and break-out tongs at 180 degrees to each other.

#### Case 1

$$H_{\max} = \frac{0.53 \times Y_m \times L \times (I/C)}{T}$$

#### Case 2

$$H_{\max} = \frac{0.38 \times Y_m \times L \times (I/C)}{T}$$

#### Where:

H<sub>max</sub> = Height of tool joint shoulder above slips - ft

Y<sub>m</sub> = The minimum tensile yield stress of the pipe - psi

L = Length of tong arm - ft

P = Line pull - lb

T = Make up torque applied to tool joint (P x L) = lb.ft

Z = Section Modulus (I/C) of the pipe – unit of length<sup>3</sup> (See table, over)

Where I = Second Moment of Area (Moment of Section) of the pipe

C = Outside radius of the pipe

Pipe OD ins	Nominal Wt lb/ft	Z (=I/C)
<b>2 3/8</b>	4.85	0.66
	6.65	0.87
<b>2 7/8</b>	6.85	1.12
	10.40	1.60
<b>3 1/2</b>	9.50	1.96
	13.30	2.57
	15.50	2.92
<b>4</b>	11.85	2.70
	14.00	3.22
	15.70	3.58
<b>4 1/2</b>	13.75	3.59
	16.60	4.27
	20.00	5.17
	22.82	5.68
<b>5</b>	16.25	4.86
	19.50	5.71
	25.60	7.25

### Tripping Procedure

1. Fill the trip tank to the highest recording level using mud from the suction tank. Do not fill the tank by diverting returns - this will allow cuttings to settle. Record the initial volume in the tank.
2. If required, and for top hole only
  - While circulating prior to tripping, prepare a heavy slug in the pill tank.  
The volume of heavy slug required is calculated as follows:  

$$\text{Slug Volume} = (\text{Drop length} \times \text{pipe capacity} \times \text{Mud wt}) / (\text{Slug wt} - \text{Mud wt})$$

**Example:** Volume of 12.0 ppg slug required to produce a level 300 ft down in 4 1/2" pipe with 9.2 ppg mud in the hole is  $(300 \times 0.01422 \times 9.2) / (12.0 - 9.2) = 14 \text{ bbls.}$
3. Prepare the trip sheet..Shut down the pump and flow check. If the hole is stable; (for top hole only - pump the slug) break out and set back the kelly.
4. When the levels have equalised and annulus flow has stopped, switch the returns to the trip tank.
5. Pull the first 5 - 10 stands without continuously filling the hole to allow the level to be visually monitored for piston type swabbing. Wiper rubbers are not to be installed until at least these 5 - 10 stands have been pulled without indication of swabbing.

Remember that bottom hole pressure is reduced by the swab pressure plus the loss of hydrostatic head due to the lower fluid level in the annulus.

**CHAPTER 4**  
**DRILL STRING EQUIPMENT**

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## 4.1 OBJECTIVES

This Chapter describes the key items of drill string equipment (jars, stabilisers and drill string barriers) applicable to GSLM's drilling activities. The information contained in this Chapter can be used to gain an informed understanding of the benefits and applications of this equipment.

## 4.2 RESPONSIBILITIES

As this Chapter primarily provides a description of drill string equipment, very few responsibilities have been defined. Those defined are tabulated below.

Task	Performed by	Verified by
Permanent provision of Inside Blowout Preventer	Drilling Contractor	DSV
Provision of two lower kelly cocks for each size of drill pipe throughout drilling operations	Drilling Contractor	DSV
Inspection and certification of all drillstring components.	Contractor	DSV
Maintaining records of all drillstring inspections on the rig	Drilling Contractor	DSV
Tracking time in hole of BHA components (jars, stabilisers, motors NMDC etc).	Drilling Contractor / DSV	DSV / DM

**Table 16. Responsibilities for Provision of Drill String Equipment at the Wellsite.**

## 4.3 DRILL STRING DESIGN

Good drill string design aims to avoid abrupt changes in component cross-sectional area as abrupt changes that lead to concentrations in bending stress, which in turn may result in a twist off. The most important components for concern are the crossovers between drill collars, drill collars and heavy weight drill pipe and heavy weight drill pipe and drill pipe.

## 4.4 BHA Handling – Notes

- Stabilisers to be made up or broken out of the drill collar string shall either be suspended by a winch line or maintained vertical by means of another mechanical support (e.g. pin in rotary table, clamp support hooked around drill collar in the rotary). Manually supporting the stabiliser without mechanical back up while engaging or disengaging the threads is not permitted. It is dangerous and may cause damage to the stabiliser pin end.
- Stabilisers and roller reamers should be gauged and visually inspected on **each** trip. Consideration should be given to laying out stabilisers that are more than 1/8" undergauge (unless drilling directionally). Serial numbers and rotating hours should be recorded on the daily drilling report.
- No chicksan connection will be made up to a down hole string component before that component is actually incorporated in the string and lowered through the rotary table to refusal or safe working height. In the event circumstances dictate otherwise, the chicksan connection shall be safeguarded by attaching a safety line to prevent free fall.
- Any threaded connection carried on top of a string suspended above safe working height and not made up to recommended torque shall be marked with chalk and continuously monitored when rotating (part of) that string.
- Avoid rotating the drill string below the rotary to make up pipe once the BHA is run. Backing the rotary into a string to make up a connection is not permitted as it can result in a dropped string or an accident due to damaged threads, and should be avoided where possible.

- Redressing of stabilisers will normally be carried out by the supplier/agent.
- Break new threads in carefully when making up for the first time. Clean thread thoroughly, make up with chain tong to recommended torque. Break connection, clean and inspect threads and remake as above.

## **4.5 JARS**

### **4.5.1 Jar Types**

There are two types of jars: mechanical and hydraulic (oil) jars. These are described in the section below.

When jarring down the smaller the quantity of drill collars placed above the jar, the higher the impact force required to free the fish. Conversely, the larger the quantity of drill collars above the jar, the greater the impulse required to move the fish after freeing the pipe.

**Mechanical Jars** (not often used).

Mechanical jars are pre-set at the surface. They are frequently used in fishing at shallow depths when there is not enough stretch in the drillpipe to create impact with the hydraulic jar.

### **Hydraulic Jars**

A hydraulic jar has a simple operation, in which overpull is applied to trip the jar, and lowering the string resets it. Jarring direction, impact intensity and frequency of impacts can all be controlled by the driller. A long stroke hydraulic jar should always be used where possible.

Some hydraulic jars are adjustable for overpull downhole and can handle torque during jarring. They are available in double-acting mode e.g. the Houston Engineers Hydra-Jar (Ref. Section 4.6.2).

Where a jar is single-acting and only jars upward, a bumper jar or sub can also be run to allow such a jar to jar in both directions..

### **4.5.2 Equipment Details**

A hydraulic jar primarily consists of two moving parts, the inner mandrel installed with the seals, and the outer body. The principal elements in a hydraulic jar that determine effectiveness and reliability are the seal system (which provides the required restriction to the passage of oil when the jar is being set) and the hydraulic oil.

The effectiveness of the seal system is dependent on the seal clearances and their ability to withstand pressure and temperature. The hydraulic oil must retain its viscosity during operating conditions to provide the necessary resistance when the jar functions, and this property is mainly affected by temperature.

Specific details of jar applications and general information on force multiplying tools are contained in Chapter 12 of this Manual.

Rotating hours shall be recorded each tour on the IADC tour report, reported daily on the Daily Drilling Report.

6 ¼" jars shall not normally be run for more than 400 hours before being replaced. If jars have been used extensively for jarring they should be replaced as soon as possible..

## **4.6 DRILL STRING STABILIZERS**

Drill string stabilisation in GSLM's drilling operations is provided by the installation of one or more of the stabiliser types outlined in the following sections. Stabiliser placement to achieve a required borehole trajectory is described in Chapter 3 of this Manual.

The following procedure should be followed with all stabilisers:

- Stabilisers will be manufactured 1/64" undergauge (for vertical wells).
- All stabilisers and roller reamers must be gauged and visually inspected on each trip.
- Stabilisers should be replaced when they are more than 3/16" undergauge (or as required for vertical wells).
- The serial number of all stabilisers run in the hole should be recorded on the GSLM daily drilling report..

### **4.6.1 Integral Blade (IB) Stabiliser**

Integral blade stabilisers are typically spiral to provide full circumference stabilisation over the total blade length. Undergauge sizes are also available for specific requirements. Blade faces are impregnated with hard-facing to prevent stabiliser gauge wear. Additional hard-facing material is applied to stabiliser shoulders.

The IB stabiliser may be a one piece, fully integral design, or a type with changeable blades.

### **4.6.2 Sleeve Stabiliser**

Sleeve stabilisers provide an alternative means to change the blades, in which a removable sleeve incorporates the stabilising blades.

The sleeve is typically screwed onto the body, and is available in a range of sizes and blade face characteristics for each hole size.

### **4.6.3 Roller Reamer**

The roller reamer typically replaces a nearbit or string stabiliser to reduce torque downhole, particularly in a packed BHA configuration, or where increased torque is anticipated such as in deviated hole.

In some cases, the effect of the rollers or cutters can be to stabilise the newly exposed borehole due to the rolling action and avoidance of relative movement between stabiliser blade and surface. Previously, this type of tool has been less reliable due to service life of roller bearings and redress difficulties. There are also concerns about the cross-sectional area with respect to hole cleaning or cuttings packing-off when POOH.

The roller reamer should be inspected every trip and should be changed out if more than



## **4.7 DRILL STRING BARRIERS**

This section describes the different types of drill string barriers. It is the responsibility of the Drilling Contractor to ensure that they are serviced and available on the drill floor as described below. The DSV shall verify their presence prior to and throughout all drilling operations..

### **4.7.1 Float Valves**

Float valves are flapper or plunger type valves that are run just above the drilling bit to prevent uncontrollable flow occurring up the drill string. An installed float valve has the disadvantage that it complicates reading the shut in drill pipe pressure after a kick.

- Float valves shall not be run in surface hole unless detailed in the drilling program.
- Flapper valves shall be run while drilling the intermediate and main hole sections unless otherwise authorised in the Drilling Program.

When using float valves, the following procedures shall be carried out:

1. When RIH, break circulation as soon as all the drill collars and one stand of drill pipe are in the hole. This confirms that the float valve is functioning correctly.
2. Fill up the drill pipe every 10 stands.
3. Run in slowly and carefully, to avoid excessive surging as the drill pipe is effectively closed.

### **4.7.2 Drop-In Check Valve**

A drop-in check valve provides an alternative to the float valve, as there is no check or restriction on return flow up the drillpipe until the check valve is installed.

### **4.7.3 Inside Blowout Preventer (IBOP)**

An Inside BOP (IBOP), also known as a Gray valve, installed with the appropriate connections for the drill string in use, shall be present on the drill floor at all times and ready for immediate use..

### **4.7.4 Lower Kelly Cock**

Two lower kelly cocks for each size of drill pipe in use shall always be available One of which shall be used below the kelly or top drive during all drilling operations. The other shall be on the drill floor complete with removable handles for easy stabbing and connecting. This valve should be kept in the open position for ease of installation..

## **4.8 INSPECTION OF DRILL STRING COMPONENTS**

All drillstring components shall be regularly inspected and certified as shown below. A record of these inspections should be kept on the rig. All BHA components must have a unique serial number to enable the usage of each component can be tracked. The table below shows the type and frequency of inspection for the various drillstring components.

ITEM	TYPE OF INSPECTION	FREQUENCY	PERFORMED BY	VERIFIED BY
<b>Drillpipe</b>	Magnetic Particle/Calliper	6 months	Inspection Company	DSV
<b>HWDP</b>	Magnetic Particle/Calliper	3 months	Inspection Company	DSV
<b>Drillcollars</b>	Magnetic Particle/Calliper	3 months	Inspection Company	DSV
<b>Crossovers</b>	Magnetic Particle/Calliper	3 months	Inspection Company	DSV
<b>Saver subs</b>	Magnetic Particle/Calliper	6 months	Inspection Company	DSV
<b>Jars</b>	Magnetic Particle/Calliper	6 months	Jar supplier	DSV
<b>Stabilizers</b>	Magnetic Particle/Calliper	6 months	Inspection Company	DSV
<b>Roller reamers</b>	Magnetic Particle/Calliper	6 months	Inspection Company	DSV
<b>Pony DC.</b>	Magnetic Particle/Calliper	6 months	Inspection Company	DSV
<b>NMDC</b>	Magnetic Particle/Calliper	6 months	Inspection Company	DSV
<b>Fishing tools.</b>	Magnetic Particle/Calliper	After use	Inspection Company	DSV
<b>MWD tools</b>	Magnetic Particle/Calliper	After use	Tool supplier	DSV
<b>Motors</b>	Magnetic Particle/Calliper	After use	Tool supplier	DSV

**Table 18. Inspection of Drill String Components**

Drillstring components that have been subjected to abnormal stress (e.g. jarring or deviated wells) will have to be inspected more frequently.

**CHAPTER 5**  
**DRILLING FLUIDS**

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## 5.1 OBJECTIVES

Selection of the correct drilling fluids is essential to:

- Drill wells safely.
- Drill wells economically whilst avoiding damage to the reservoir or adversely affecting the quality of the evaluation programme.

Every well must have a Drilling Fluids Program which shall be designed to:

- Prevent the influx of formation fluids.
- Minimise reservoir damage.
- Enable the efficient acquisition of data for evaluation.
- Economically overcome potential hole problems by providing the necessary properties for pressure control, hole stability, hole cleaning and formation inhibition.
- Limit the environmental damage caused by discharges of materials and fluids.

The basic API drilling fluids tests shall be conducted at least twice daily during drilling operations and the latest test included on the Daily Drilling Report.

The environmental impact of the drilling fluids system must be evaluated and disposal of drill cuttings, drilling fluids and other wastes must be carried out in accordance with GSLM's guidelines and relevant Government legislation.

All toxicological properties of drilling fluids additives must be understood and controlled. Copies of the MSDS must be held at the wellsite for ALL mud chemicals on location.

## 5.2 RESPONSIBILITIES

The general responsibilities for planning, preparing and maintaining drilling fluids are outlined in the table below.

Task	Performed by	Verified by
Prepare Drilling Fluids Program	Drilling Fluids Contractor	DM
Monitor and maintain the drilling fluid properties in accordance with the Drilling Fluids Program	Drilling Fluids Engineer	DSV
Conduct routine testing and reporting, advise on any related problems	Drilling Fluids Engineer	DSV
Provide technical and commercial overview of the drilling fluids operation and make recommendations for improvements	DSV/ Drilling Fluids Engineer	DM
Treat the drilling fluids and ensure relevant personnel adhere to the safe handling procedures for chemicals and equipment	Drilling Fluids Engineer / Derrickman	DSV
Ensure that the Barite and drilling fluids stocks are maintained above the minimum levels as per 3.3.2	Drilling Fluids Engineer	DSV
Maintain equipment associated with the handling and treatment of drilling fluids	Drilling Contractor	Drilling Fluids Engineer / DSV
Ensure that health safety and environmental requirements are complied with on site	Drilling Fluids Engineer / Drilling Contractor	DSV
Ensure mud chemicals are correctly stored and transported.	Drilling Fluids Engineer / Drilling Contractor	DSV
Compile Daily Reports	Drilling Fluids Engineer	DSV

**Table 19. Responsibilities for Planning, Preparing and Maintaining Drilling Fluids.**

The parties responsible for performing the work must ensure that they understand all relevant procedures. They must pre-plan the work, issue instructions for all tasks and be responsible for coordinating the pre-job meeting which shall detail all aspects of the activity.

### 5.2.1 Detailed Responsibilities for Key Personnel

The Drilling Contractor, Drilling Fluids Engineer and DSV shall work together to ensure that the drilling fluids are handled, maintained and treated in a manner which fulfils the requirements and objectives of GSLM, as outlined in the Drilling Program.

#### 5.2.1.1 Drilling Contractor

The Drilling Contractor shall ensure that all the equipment associated with the handling and treatment of drilling fluids is functioning correctly and is regularly checked and maintained. In addition, the Drilling Contractor shall also liaise with the Drilling Fluids Engineer when:

- Making regular drilling fluids checks.
- Mixing drilling fluids.
- Monitoring drilling fluids.
- Storing and handling chemicals.
- Operation and maintenance of solids control equipment.
- Maintaining an inventory of spares/back-up equipment for the solids control equipment.

#### 5.2.1.2 Drilling Fluids Engineer

The Drilling Fluids Engineer shall be responsible for all issues relating to drilling fluids, including storage at the wellsite, transport and usage during a well operation. The Drilling Fluids Engineer shall ensure the following functions are performed in accordance with the GSLM operational guidelines contained in this Chapter.

- Ensure that the Drilling Fluids Program is followed and that costs are closely monitored.
- Maintain and monitor the drilling fluids properties to specifications outlined in the Drilling Program. Any parameter outside of specification should be noted on the daily mud report.
- Ensure routine testing and reporting is carried out and advise the DSV of all related problems as and when they occur, recommending the appropriate treatment for the drilling fluids. Provide the DSV with the technical and commercial overview of the drilling fluids operation and make recommendations for improving the program or operations as and when necessary.
- Recommend, manage and supervise all treatments to the drilling fluids that shall be based on sound technical and commercial evaluation and pilot testing.
- Ensure all relevant personnel are aware of, and adhere to, the safe handling procedures of all drilling fluids chemicals and equipment (reference Chapter 1 of this Manual).
- Determine the required drilling fluid materials and recommended equipment (e.g. chemicals, shaker screens etc.). Communicate to the DSV to ensure timely requisitioning of same.
- Optimise the solids control equipment to minimise losses and control low gravity solids levels in the drilling fluids. All such equipment suction, returns and discharges shall be monitored and their performance reported daily to the DSV.
- Together with the Drilling Contractor, ensure that the health, safety and environmental objectives of the Drilling Fluids Program are met at the wellsite.
- In conjunction with this, ensure that the disposal of waste fluid and wellbore materials conforms with all relevant GSLM's procedures and Government regulations.

- Ensure that a current copy of Material Safety Data Sheet (MSDS) for each chemical is kept at the rig (Chapter 1 of this Manual).
- Compile all reports required by the Company and the regulatory authorities relating to the transfer, storage, use and maintenance of all drilling fluids and related additives and equipment (Chapter 1, this Manual).
- Compile all drilling fluid Recaps on time and ensure that they contain information required for future well planning.
- Manage stock – Cycle ageing products, ensure stocks are covered, packed, stored and transported correctly so as to minimise damage.
- Record the number of hours the solids control equipment is run each day.
- Record shaker screen usage.

### **5.2.1.3 Drilling Supervisor**

The DSV shall ensure that the quality control of drilling fluids operation, maintenance and treatment is performed and adhered to in a manner that fulfils the well requirements. This shall include, but not be limited to the following:

- In conjunction with the Drilling Fluids Engineer recommend adjustments to the drilling fluid properties to ensure optimal mud performance.
- Perform quality checks on the drilling fluids testing carried out by the Drilling Fluids Engineer.
- Ensure that the Drilling Fluids Engineer submits the required accurate reports on time.
- Ensure that the Drilling Fluids Engineer carries out mud mixing in accordance with the Drilling Fluids Program.
- Ensure that the Drilling Fluids Engineer assists with the optimisation of the solids control equipment.
- Ensure the Drilling Contractor maintains, and optimises the solids control equipment.
- Verify that the Drilling Fluids Engineer maintains an up to date inventory of all drilling fluids material and testing equipment.
- Monitor the usage of shaker screens.

## **5.3 STANDARDS**

This section describes the generic drilling fluids types used during drilling operations and the minimum drilling fluids requirements to be held at the wellsite..

### **5.3.1 Drilling Fluids Standards**

This section describes the standard drilling fluids types, ingredients and formulations of drilling fluids used in drilling operations.

#### **5.3.1.1 Drilling Fluid Types**

The generic drilling fluids types that may be used by GSLM are listed below. Additional detail is provided in the remainder of this Chapter:

- Prehydrated Gel (PHG)/ Spud mud.
- Enhanced Spud mud.
- KCl/ PHPA Polymer.
- KCl/Polymer.
- KCl Brines.

### **5.3.1.2 Primary Ingredients**

The primary fluid systems ingredients and their applications are outlined in the table below.

An overview of formulation ranges for each drilling fluid type is shown in Section 5.3.1.3.

Primary Function	Generic / Common Name	Chemical Composition	Typical Uses
<b>Alkalinity Control</b>	Caustic Soda	Sodium Hydroxide NaOH	Adjust pH; treat out Magnesium hardness
	Caustic Potash / KOH	Potassium Hydroxide KOH	Adjust pH; treat out Magnesium hardness; K+ source
	Soda Ash	Sodium carbonate	Treat out Calcium hardness/ cement in low pH muds.
	Bicarb	Sodium Bicarbonate	Treat out cement contamination in high pH muds
	(Slaked) lime	Calcium Hydroxide	Increase viscosity by flocculation of clays; raise pH; treat Carbonate / CO2 gelation problem; Ca++ source
	Citric Acid	Citric Acid	Decrease pH and stop polymer burn -out/ degradation
	SAPP	Sodium Acid Pyro Phosphate	Cement pre-flush additive: thinner sequesters calcium
<b>Biocide</b>	Alkyl Dithiocarbamates		
	Glutaraldehyde	Glutaraldehyde	Prevent bacterial decay of polymers
<b>Corrosion Control</b>	Filming Amine	Proprietary blend	Minimise corrosion of tubulars from oxygen, CO2 and/or H2S
	Multi- component	Proprietary blend	Minimise corrosion of tubulars from oxygen, CO2 and/or H2S
	Zinc Carbonate	Zinc Carbonate	Hydrogen Sulphide scavenger
	Liquid Oxygen Scavenger	Ammonium Bisulphite	Minimise corrosion of tubulars from oxygen
	Solid Oxygen Scavenger	Sodium Sulphite	Minimise corrosion of tubulars from oxygen
<b>Defoamer</b>	Defoam	Proprietary	Defoam aerated muds, surfactant
	Stearate	Aluminium stearate	Defoam aerated muds
<b>Detergent</b>	Mud detergent, DD, etc.	Metallic salty of fatty acid (soap)	Minimise bit balling, emulsifier, rig wash
<b>Dispersant</b>	CF Ligno	Chrome free Lignosulphate	Thinner; reduces fluid loss, emulsifier, shale inhibitor
<b>Fluid Loss Control</b>	PAC LV and/ or PAC REG	Polyanionic cellulose	Reduces fluid loss: viscosifier (YP).
	Starch	Carbohydrate	Reduces fluid loss; inhibits shale hydration / dispersion
	Lignites (Lignon Tannathin, etc)	Lignin resins	Reduces fluid loss; thinner
	CMC LV, CMC REG and/ or CMC HV	Sodium Carboxymethyl cellulose	Reduces fluid loss; viscosifier
	Acrylate (SP 101, Cypar, etc	Sodium Polyacrylate	Reduces high temperature fluid loss; thinner
	Modified polymers	Proprietary Organic polymers	Reduces high temperature fluid loss; thinner
<b>Shale Inhibitor</b>	PHPA	Partially hydrolysed polyacrylimide	Reduce shale hydration by encapsulation; viscosifier
	Salt	Sodium Chloride NaCl	Inhibits shale hydration brine additive (max. 10.0 ppg)
	KCl	Potassium Chloride KCl	Inhibits shale hydration brine additive (max. 9.7 ppg); K+ source
	Polyol	Glycol / Glycerol	shale inhibitor, lubricant blend

**Table 20. Primary Drilling Fluids Ingredients (i)**



Primary Function	Generic / Common Name	Chemical Composition	Typical Cooper Basin Uses
<b>Viscosifiers</b>	Trugel (various nos)	Locally processed Bentonite	Peptised/ polymerised gel viscosifier (FWYP/gels)
	Wyoming Bentonite	Imported pure Bentonite	Used as cement additive (extender) no polymers
	Biopolymers (XC, XCD, etc.)	Xanthium gum and/ or derivatives	Raise viscosity (YP, gels and low-end rheology)
<b>Weighting Agents</b>	Barite	Barium Sulphate (+ minor metallic ores)	Inert Weighting material (max 20 ppg)
	Limestone	Calcium Carbonate	Acid soluble weighting material (typical / max 12.0 / 16.5 ppg)
<b>Miscellaneous</b>	Calcium Chloride	Calcium Chloride	Brine additive (max. 11.7 ppg); cement accelerator
<b>Lost Circulation Material</b>	Mica – coarse, medium, fine	Muscovite flakes	Reduce seepage losses – total lost circulation
	Cereal husks	Cellulosic fibre materials	Reduce seepage losses – total lost circulation
	Ground shells	Ground Walnut hulls	Reduce seepage losses – total lost circulation
	Limestone	Calcium Carbonate	Reduce seepage losses – total lost circulation
	Fibrous blend	Fibrous flakes and granular blend	Reduce seepage losses – total lost circulation
<b>Pipe Free Agent</b>		Proprietary surfactant blend	Soak solution for differentially stuck pipe

**Table 20 (cont'd) Primary Drilling Fluids Ingredients (ii)**

### 5.3.1.3 Standard Formulations

The relevant Drilling Fluids Program takes precedent over the formulations shown in the Drilling Operations Manual.

### 5.3.2 LCM Standards

Lost circulation or lost returns is defined as the loss to the formation of either drilling fluids or cement slurry used during the drilling or completing of wells.

The recommended Lost Circulation Material (LCM) that may be used across reservoirs etc. to minimise formation damage is normally a cellulose type product such as Enerseal super fine, Sandseal .

### 5.3.3 Stuck Pipe Spotting Fluids (Pipe Free Pills)

Spotting fluids should only be used when so directed by the DM.

Spotting fluids should be mixed and pumped according to the manufacturer's recommended formulation and procedures, under the following guidelines:

- The pill should be prepared in a clean tank on surface. The volume required shall be determined by the DSV and shall be 50 - 100 % excess over the annular volume around the drill collars.
- Consideration should be given to the density of the pill, which should ideally be the same or greater than the density of the drilling fluids, to minimise the migration of the pill through the static mud column.

Standard spotting fluid volumes and compositions are shown below:

**Mixing -** 20 bbl pill: mix 1 drum (55 gals) surfactant in 19 bbl diesel.  
40 bbl pill: mix 2 drums surfactant in 38 bbls diesel.

#### 5.3.4 Minimum Chemical Stock Requirements

The following are the minimum chemical stocks that shall be available for use on the rig. These may either be kept on the rig or at a nearby supply base if transport is readily available.

- Mud chemical stocks adequate to re-build 1½ times the maximum hole volume plus the minimum surface volume of the mud system in use and the interval being drilled.
- The mud system in use and the interval being drilled.
- Emergency barite stocks to be able to weight the total mud system by at least 1.0 ppg.
- Sufficient stocks of LCM material for both above and across the reservoir.
- Sufficient stock of surfactant, weightable pipe freeing agent, Biocide and corrosion inhibitor materials.

The DSV and DM shall individually review specific well requirements.

#### 5.4 SOLIDS CONTROL AND MUD RELATED EQUIPMENT

Solids contamination of drilling fluids is the single most costly drilling fluids control problem. Mechanical treatment is the most economical means of treatment (shakers, desanders, desilters, and centrifuge). The quantity of solids removed must be maximised. However, complete removal of undesirable solids is not practicably feasible.

Mechanical treatment must begin immediately drilling commences rather than to delay until the mud properties start to deteriorate as this will result in the requirement for dilution or treatment with costly chemicals.

The following are the GSLM's solids control guidelines:

- All applicable equipment shall be operating and functional before drilling begins.
- Solids control equipment shall be maintained to appropriate standards.
- Efficiency checks shall be made daily when equipment is in use.
- Manufacturers Maintenance and Operating Manuals for all solids control equipment shall be available at the wellsite.
- Instructions for use and maintenance shall be strictly adhered to at all times.
- Linear motion shakers are the preferred shaker type.
- The vacuum degasser system (where available) should be tested at the start of each well and prior to any DST's.
- The finest practical shaker screens will be used.
- Shaker screens should be inspected frequently and any damaged screens repaired or replaced. The mud engineer should record screen usage on the daily mud report.
- The settling tanks should never be bypassed and should be dumped regularly.
- Desanders and Desilters should be balanced to produce a spray discharge.
- Reuse sump water where possible.

### **5.4.1 Operations Guidelines for Solids Removal and Equipment**

This section describes equipment provided by the Drilling Contractor and the methods for the removal of solids.

#### **5.4.1.1 Flowlines and Jet lines**

Flowlines, shaker header boxes (possum bellies) etc., shall be inspected regularly and cleaned out as required, to prevent solids build-up.

Jet lines, if fitted, shall also be inspected regularly to ensure that they function properly.

### 5.4.1.2 Shale Shakers

Equipment	Operational Guidelines
Shale Shaker	<ul style="list-style-type: none"> <li>• Must be operated as efficiently as possible, at all times, in order to maximise the amount of solids removed after exiting the wellbore.</li> <li>• Must be switched on immediately before running in the hole to clean the mud displaced by the drill string and BHA.</li> <li>• Flow shall be distributed evenly over all available shakers.</li> <li>• Shakers shall be switched off immediately prior to tripping out of the hole. Care must be taken to ensure that the shakers are started before breaking circulation for any reason, e.g. backreaming and pumping out.</li> <li>• Cuttings should not be allowed to dry hard upon the screens.</li> <li>• Shakers shall not be by-passed, unless absolutely necessary and as authorised by the DSV</li> <li>• Shakers should not be run dry as this leads to increased wear and premature screen failure</li> </ul>
Shaker Screens	<ul style="list-style-type: none"> <li>• The finest mesh screens shall be selected, taking into consideration maximum solids separation whilst minimising the loss of whole mud, and ensuring that screens are not overloaded.</li> <li>• Screens shall be inspected regularly and changed out or patched immediately when defects are identified.</li> <li>• Operations should not be allowed to continue with a torn or ineffective screen.</li> <li>• Screens shall be washed down regularly e.g. on connections, prior to tripping out of the hole and before shakers are switched off.</li> <li>• Adequate stocks of screens, in an appropriate range of sizes, shall be maintained on location at all times.</li> <li>• The mud engineer should record the number of screens used on the daily mud report.</li> <li>• Ensure shaker screens are installed and tensioned as per the manufactures procedures</li> </ul>

**Table 21. Operational Guidelines for Shale Shakers**

With new water based polymer mud, screen blinding may occur during the initial period of circulation. After one or two circulations, the shakers may be redressed with finer screens as the polymer shears , or the mud heats up.

A reduction in circulation rate and/or changing to coarser screens should alleviate screen blinding problems and drilling fluid losses arising from high viscosity drilling fluids and/or solids-laden drilling fluid after trips. However, circulation rate must only be reduced if it is absolutely certain that effective hole cleaning can be maintained.

### 5.4.1.3 Settling Tanks

This section describes the operational guidelines for settling tanks. Settling tanks shall:

- Not be by-passed.
- Be checked and dumped regularly.
- Not be dumped while circulating, as a dump valve malfunction could result in suspension of operations.

The operation of the dump valve shall be checked every time the settling tank is dumped and cleaned out. It is not always necessary to dump the complete contents of the settling tank, since this results in the immediate need for a large replacement volume within the circulating system. It may be easier to operate if smaller volumes of solids are dumped at more regular intervals.

Settling may be assisted by dilution, with water, to the returns flowline. However, this practice should not be routinely used with a weighted mud system.

#### 5.4.1.4 Desanders and Desilters

The table below highlights the performance characteristics of the hydrocyclone equipment used for desanders and desilters, and provides an operational troubleshooting guide which may be used to rebalance a unit that is not correctly set up. Incorrect operation is extremely inefficient, and normally results in an excessive wastage of whole mud.

Underflow	Cause	Wear Pattern	Remedy
Spray discharge	Correctly set up	Grooving over lower two inches	None required.
Rope discharge	Overload of solids in feed and/or undersized cone apex (possibly caused by plugging)	Sharp grooving 1/3 way up cone and erosion of cone top due to solids in overflow	Increase apex size until spray discharge is achieved. If unsuccessful remove cone and clean out underflow blockage
Continuous flow discharge	Low inlet velocity that could be due to low feed head. Could also be caused by partial or total plugging of feeder head	Excessive wear at cone apex	Strip and clean feed header and regulate pump to provide + 75ft of head
Plugged discharge	Underflow plugging at cone apex caused by solids overload and/or restriction in underflow opening	Sharp grooving 1/8 way up cone and erosion of cone top due to solids in overflow	Strip down cone. Clean out blockage and reset apex size

**Table 22. Hydrocyclone Troubleshooting Guide**

In principle, desanders and desilters should only be run with unweighted water-based muds, and consideration should also be given to their use with polymer muds, as a significant proportion of material can be discarded in the process. It is essential that they are properly set up and adjusted.

Desanders and desilters shall be run under the following guidelines:

- Run on a continuous basis when appropriate, to assist in maintaining a low mud weight.
- Balanced to produce a spray discharge.
- Periodically flushed with water (particularly if they have been shut down for a period), to remove any caked solids that could lead to plugging of the feed nozzles or apex bushings.
- For optimum performance, the desander overflow should be rigged up to discharge into the desilter suction tank.
- Each desander and desilter shall be assigned a dedicated pump.
- Where possible, ultra-fine mesh screens should be used on the high speed shakers. This will minimise the requirement for hydrocyclones.

The following guidelines regarding the operation of the cones shall be followed:

- Cones shall be stripped and cleaned after every period of continuous (e.g. at the end of each well) use, particularly the feed nozzle, the two apex adjusting bushings and the body liner. Wear can critically affect hydrocyclone performance.
- The pressure operating within a cone is adjusted by the two apex bushings or the triangular bushing on each cone, and their size also affects the pressure. If large opening bushings are used, a higher capacity centrifugal pump may be required to maintain the optimum feed pressure.
- Required running pressure is as follows:  $Pr(\text{psi}) = (MW/8.34) \cdot 75 \cdot 0.433$

## **5.5 MONITORING, REPORTING AND TESTING**

This section describes the monitoring, reporting and testing of drilling fluids as performed by the Drilling Fluids Engineer.

### **5.5.1 Drilling Fluids Monitoring**

The Toolpusher shall designate a suitably trained rig crew member to monitor the shale shakers and mud pits at all times while circulating. Part of the designated duties shall be to measure and record the mud density and funnel viscosity of the drilling fluid at the times shown in the Monitoring Report.

Mud weight and Funnel Viscosity tests shall be carried out on samples taken from the flowline and the suction pit every 30 minutes, or more frequently as determined by the Drilling Fluids Engineer and DSV.

The Drilling Contractor designated personnel shall record all drilling fluids test results and pit levels, where appropriate, in a book containing a format similar to that shown above.

The book shall:

- Be kept in a convenient place for ease of inspection by supervisory personnel.
- Contain all instructions passed to the designated crew member by the Drilling Fluids Engineer or DSV, clearly marking the time and date of the instruction.

The DSV shall determine the required mud weight to ensure safety of personnel and integrity of the wellbore, and shall advise the Drilling Fluids Engineer and the Drilling Contractor of this value.

When any departure from the mud weight specification is detected, the Drilling Fluids Engineer or Drilling Contractor shall inform the DSV immediately..

### **5.5.2 Drilling Fluids Testing and Reporting**

The Drilling Fluids Engineer shall perform a full mud check at least twice daily during drilling operations and record the results on the Daily Mud Report Form. The mud check run closest to the 06:00 depth will be used on the Daily Drilling Report.

Additional reporting on the management of the drilling fluids, chemical usage and solids control equipment shall be performed by the Drilling Fluids Engineer or the DSV on a daily, per well and as required basis. Copies of all reports shall be submitted to the DSV for verification.

The Drilling Fluids Recap shall be continually updated by the Drilling Fluids Engineer during the course of the well. Upon completion of the well, the edited and checked document shall be forwarded at the earliest opportunity to the DM.

### **5.5.3 Water Based Mud Testing Requirements**

The table below summarises the minimum drilling fluids tests required during drilling operations. Additional tests are at the discretion of the DM and DSV, and may also be planned on a well by well basis. All test results shall be recorded on the Daily Mud Report in API Standard Units. These shall be performed by the Drilling Fluids Engineer in accordance with the testing frequency.

<b>Drilling Fluids Property</b>	<b>Unit of Measurement</b>	<b>Standard or Calibration</b>	<b>Measuring Equipment / Method</b>
<b>Mud Weight</b>	ppg	8.34 ppg with fresh water	Mud balance
<b>Funnel Viscosity</b>	sec/qt	26.5 sec with fresh water	Marsh funnel and mud cup
<b>Rheology</b>	rpm	600,300, 200, 100, 6 & 3 rpm.	Six speed rheometer and heating cup
<b>Plastic Viscosity (PV)</b>	cps	600 minus 300	"
<b>Yield Point (YP)</b>	lbs/100sq.ft	300 rpm - PV	"
<b>Gel Strength</b>	lbs/100sq.ft	3 rpm at 10sec, 10min and 30min	"
<b>API Fluid Loss</b>	cc(or ml) per 30 min	Performed at 100psi and ambient temperature	API
<b>HPHT Fluid Loss</b>	cc(or ml) per 30 min multiplied by 2	Performed at 500psi and maximum TD temperature	HTHP filter press
<b>Filter Cake</b>	mm or 32nd inch	Description	From fluid loss test
<b>Oil/Water/Solids</b>	% (HGS and LGS) by volume	Test with water (100%)	Retort kit
<b>Sand Content</b>	% by volume	Test with known solutions	Sand kit
<b>pH</b>	acid / alkalinity (0 to 14 scale)	pH test meter	pH meter, colour strips / litmus paper.
<b>Methylene Blue Test (MBT)</b>	lbs/bbl (5 x cation exchange capacity)	Test with known solution	MBT test kit
<b>Chlorides</b>	Mg/l	Test with known solution	Filtrate titration
<b>Potassium Ion / KCl</b>	Mg/l / %	Test with known solution	Titration / centrifugal precipitation
<b>Hardness (Ca and Mg)</b>	Mg/l	Test with known solution	Filtrate titration
<b>Alkalinity (Mud &amp; Filtrate, Pm, Pf, Mf)</b>	ml standard sulfuric acid	Test with known solution	Mud and filtrate titration
<b>PHPA</b>	lbs/bbls (ml or cc precipitation)	Test with known solution	Centrifugal precipitation

**Table 24. Minimum Drilling Fluids Testing Requirements, Units and Standards**





## CHAPTER 6 TRAJECTORY CONTROL

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## 6.1 OBJECTIVES

The objectives for trajectory control are as follows:

- Attain the required bottom hole position within the required tolerance.
- Achieve the planned trajectory without a Dogleg Severity that exceeds the programmed specification.

In most cases, well trajectory control simply means ensuring that a planned vertical wellbore is drilled vertically.

**Note:** GSLM shall survey all wellbores from surface to TD, with instruments suitable for this use.

## 6.2 RESPONSIBILITIES

Responsibilities for the implementation, supervision and verification of directional drilling and surveying are tabulated below.

Task	Performed by	Verified by
Specification of target and surface location	Geology Dept	DM
Preparation of well trajectory plan and kick-off point	Directional Contractor	DM
Equipment selection	DM	DM
Call out of contractor supplied equipment	DM	DM
Monitoring well trajectory	DSV	DM
BHA design and bit selection	DSV / DM	Dm
Wellbore surveying	DSV / Drilling contractor	DSV / DM

**Table 25. Responsibilities for Implementation, Supervision and Verification of Directional Drilling and Surveying.**

## 6.3 GENERAL SURVEY REQUIREMENTS

The surveying program shall be defined in the Drilling Program, based on the guidelines below.

Surveys are normally performed using the Totco or Magnetic Single Shot (MSS) tool. Directional surveys can also be run as part of the wireline logging program.

Survey tool selection may be reviewed however, depending on target size and depth, and the level of accuracy required. Survey intervals shall be specified for each well.

The following table provides an outline of the minimum standard survey parameters for vertical wells. Note: Survey frequency may be increased if the deviation increases above the specified limits.

Interval	Survey Tool	Frequency	Maximum Inclination	Maximum DLS
<b>Surface hole</b>	MSS/Totco	Every 150 m	3 degrees	1.5 degrees/30 m
<b>Intermediate hole</b>	MSS/Totco	Every 150 m	5 degrees	1.5 degrees/30 m
<b>Production hole</b>	MSS/Totco	Every 150 m	6 degrees	1.5 degrees/30 m

**Table 28. Standard Survey Parameters for Vertical Wells**

If the surveys fall outside the above parameters the DM should be notified. No corrective action should be taken without consulting with the DM. Confirm with DM before running surveys through or below known depleted zones.

All survey instruments shall be run as close to the bit as possible. The hole must be sufficiently circulated prior to running surveys (this will normally be at least 1x bottoms up), to ensure that hole conditions are stable and the drill string is kept stationary for as little time as possible.

All surveys recorded on the daily drilling report shall be referenced to Magnetic North, not True North or Grid North. Surveys will be corrected to true north by the DM. Directional surveys will normally reference grid north.

## 6.4 DIRECTIONAL DRILLING

This section describes the planning, implementation and verification of surveying requirements during drilling operations on deviated or high angle wells.

### 6.4.1 Planning Requirements

The Drilling Program contains all the information necessary for the preparation and commencement of directional operations. As such the DSV shall check the Drilling Program and associated documentation to ensure that it contains the following:

- Assumed ground level elevation above M.S.L.
- Target co-ordinates, target size and tolerance(s).
- Origin Reference Points for the applicable well surface location.
- Kick-off point, build and turn rates.
- Survey Program.
- Recommended BHA's to be used including agreed dogleg severity potential values for each assembly. The BHA's quoted are to be used as a guide and modified as drilling conditions and directional requirements dictate.

Where the above data has been omitted, it shall be requested by the DSV before the start of operations. The DSV shall ensure that all well plots are available. However no well plots are required for standard vertical wells.

### 6.4.2 Survey Requirements

All wells shall be surveyed from the wellhead to TD using the guidelines specified in Section 6.3 of this Manual and those below.

Task	Description
<b>Planning</b>	<ul style="list-style-type: none"> <li>• Survey type shall be based on the anti-collision requirements (if applicable), survey tool accuracy, target size and depth.</li> <li>• Survey accuracy objectives shall be specified for each well.</li> </ul>
<b>Calculations</b>	<ul style="list-style-type: none"> <li>• The preferred method of survey calculation is the Minimum Curvature method. Other calculation methods may be used to verify survey results.</li> <li>• Magnetic interference calculations based on region and well orientation shall be performed by the Directional Contractor to determine the minimum length of non-magnetic drill collars and stabilisers if required for clean magnetic surveys.</li> </ul>
<b>Reporting</b>	<ul style="list-style-type: none"> <li>• All survey data reported to on the Daily Drilling report shall be UNCORRECTED (e.g. referenced to magnetic north).</li> <li>• The Azimuth shall be reported in degrees and not quadrants (i.e. will be reported as 190° not S10°W).</li> <li>• The values for convergence and declination used shall be reported on all definitive surveys. Survey tool accuracy shall be specified on all definitive surveys presented to GSLM.</li> <li>• Survey results shall be referenced to the local grid for reporting purposes.</li> </ul>
<b>Verification</b>	<ul style="list-style-type: none"> <li>• The quality of all multi-shot surveys taken shall be checked by the Surveying</li> </ul>

	Contractor and verified by the DSV using the approved acceptance criteria (Refer 6.5.1).
--	--

**Table 27. Survey Requirements.**

### 6.4.3 Magnetic Survey Equipment

All downhole survey instruments shall have a valid inspection certificate and shall conform to standard DS-1 Drilling Service Category 4. For normal use, certificates shall be valid for a period of up to 18 months; however if any tool has been subjected to rough treatment or has produced erroneous survey data, then it shall be returned to the certified re-calibration facility for re-calibration and testing.

Magnetic interference calculations based on region and well orientation shall be performed by the Directional Contractor to determine the minimum length of non-magnetic drill collars (and stabilisers if applicable) required for clean magnetic surveys.

All tools supplied to the rig shall be accompanied by the appropriate documentation. In accordance with good oilfield practice, all pin connections shall be stress-relieved and all boxes bored back.

From time to time, as operations progress, additional information will be required by the Directional Contractor to facilitate accurate monitoring and reporting of the borehole position. The DM shall ensure that this information is transmitted to the rig, marked for the attention of the DSV, as and when required.

 Standard DS-1 Drilling Service Category 4.

### 6.4.4 Tie-In Data

For directional wells, tie-in data shall be provided by the Directional Contractor after completion of quality assurance checks on each multi-shot survey.

The Directional Contractor shall forward the data to the DM, who shall validate the results and issue the following data to the rig:

- Tie-in depth RT (m).
- Inclination (degrees).
- Azimuth (degrees).
- TVD RT (m) - True Vertical Depth Rotary Table.
- Northing (m).
- Easting (m).
- Ground Level (m asl)

### 6.4.5 Position Uncertainty

Borehole position uncertainty can be evaluated in the lateral, radial and vertical directions for both 'good' and 'poor' quality magnetic and gyro surveys. For most practical cases, lateral position uncertainty is the greatest and therefore can be used to estimate borehole position uncertainty.

Computed survey errors have been used to produce curves showing the lateral position uncertainty for various survey tools. These have been normalised to express the relative position uncertainties in feet per 300 m AHD against average inclinations.

Appendix 1 of this Chapter contains a set of curves demonstrating tool comparisons, and provides an approximation of the position uncertainty of a well. Ellipses of uncertainty are included in this section as a quick look guide.

## 6.5 GENERAL SURVEY PRACTICES AND GUIDELINES

This section describes running guidelines for wireline, multishot and MWD survey equipment and describes the quality control procedures associated with running the tools.

### 6.5.1 Wellsite Survey Quality Control Procedures

It is the responsibility of the DSV to ensure that the following procedure is performed, following completion of a well survey:

1. The Surveying Contractor shall report the data obtained for each survey run to the DSV.
2. The DSV shall check reported values conform to the acceptance criteria outlined below:

The Variance Between the:	Shall not Exceed
In-run and out-run inclination values for survey data from the same survey station	0.23 degrees
In-run and out-run azimuth values from the same survey Station	1.0 degree for all stations having an inclination of 10 degrees or over
In-run and out-run azimuth values from the same survey station	5.0 degrees for all stations having an inclination below 10 degrees

**Table 29. Acceptance Criteria for Well Surveys**

3. When the acceptance criteria are met, no further well site QA / QC shall be performed. The final survey report shall be subjected to a full quality control examination by the DM.
4. In the event that all the acceptance criteria are not met, the DSV shall inform the DM who shall advise further action. Repeat surveys shall only be undertaken with the full approval of the DM.
5. In the event of a survey miss-run, DM approval for a repeat survey shall not be required. In this instance the DSV shall ensure that all questionable equipment is replaced with fully checked-out units prior to the re-run of the survey.

### 6.5.2 MWD Running Guidelines

The MWD tool is a combined magnetic steering and surveying tool run close to the bit. It measures inclination, azimuth and toolface. The following guidelines shall be observed when running an MWD:

- Measure the fishing neck of the MWD tool.
- Run mud filter screens. It is preferable to have these installed in the surface equipment rather than in the top drill pipe single.

- Considerable care should be taken whenever handling MWD tools. They are built to withstand high axial loads but are easily damaged by transverse loading. MWD collars should always be snubbed when being handled out of transport cradles.
- Surveys should always be taken after making a connection in order to reduce the chances of stuck pipe. Although the pipe should remain stationary when the survey is being taken it should be reciprocated during transmission of the data to surface.

Benchmarking surveys should be taken in accordance with the MWD Survey QA/QC guidelines detailed below..

### 6.5.3 MWD Survey QA/QC Guidelines

The following guidelines should be routinely applied to assess the validity of MWD survey data. Adherence to the procedures below will assist identification of incorrect data.

#### 6.5.3.1 Surface Function Test

The MWD tool shall be function tested at surface according to contractor procedures. Two tools should be prepared to ensure a back-up is ready in the event that the surface test fails. The tests shall be performed as follows:

1. Make up the MWD, aligning the scribe mark on the motor or bent sub to the MWD. The toolface offset shall be recorded by the Directional Drilling Contractor who shall supervise the operation.
2. Circulate directly above the MWD (with the bit and motor made up) at the planned flow rate.  
Record pressure versus flow rate and check performance of the tool.
3. Check the total gravitational field readings that should be close to unity.

#### 6.5.3.2 Benchmark Survey

The following guidelines should be adhered to when performing a benchmark survey:

1. Take a survey in open hole at a suitable survey station at least 100' below the previous casing shoe to avoid magnetic interference and in order to provide a benchmark. Survey inclination should be within 0.5 degrees of the survey originally recorded at this station.  
Survey azimuth should agree within 2 degrees for survey stations above 10 degrees inclination.
2. Repeat the benchmark survey at the final survey station of the previous bit run before drilling ahead.
3. If the benchmark survey does not meet the above criteria, work the pipe and check the survey again at this or the following previously surveyed station.

**Note:** Repeatability of benchmark survey results is prone to variance below 10 degrees of hole inclination. BHA centralisation, borehole anomalies, washouts and deformations could be the cause lack of repeatability. In the event of failure to meet the benchmarking acceptance criteria the DE shall advise further actions.

### **6.5.3.3 Survey Quality Checks**

When the MWD tool transmits a sequence of quality control outputs with every survey, they can be used to validate the quality of the survey and check the correct functioning of the tool.

The level of quality control that is possible with the MWD depends on the number of “full survey” stations which have been obtained with the particular MWD tool within the hole section. At least the first, fourth, seventh, etc, stations shall be taken in full survey mode.

When long survey quality control outputs are obtained, the DSV shall check that all raw magnetic values are similar to computer predictions for the date and location provided by the MWD Service Contractor.

## 6.6 DIRECTIONAL DRILLING – ROTARY

During directional drilling the DSV shall supervise and monitor the activities of the Directional Drilling Contractor on behalf of GSLM.

### 6.6.1 General Guidelines

In general, only the bit, drill collars, and stabilisers are considered for trajectory control. The specific drilling operation shall determine the rest of the BHA components (e.g. shock subs, hammers, mud motors, MWD, jars, accelerators, heavy weight drill pipe, transitional drill collars, etc.).

The following guidelines should be considered when checking the proposed BHAs.

- Only the lower 30 m of the BHA provides deviation control. More drill collars and additional stabilisers are used to provide additional weight and to provide standoff from the wellbore and to prevent drill collar "wobble" during drilling.
- In areas of strong formation dip, local knowledge, experience and computer modelling should be used when selecting BHAs to build or maintain hole inclination. These assemblies are more susceptible to the azimuth tendencies imposed by strongly dipping formations. Stabiliser sizes should be varied at the discretion of the Directional Drilling Contractor depending upon conditions encountered in individual wells.
- The following calculation shall be used to determine the neutral point of buckling:

$$\text{Weight of BHA in Air} = \frac{\text{Required WOB}}{\text{Bouyancy Factor} \times \text{Safety Factor}}$$

The Safety Factor depends upon the type of BHA stabilisation. It is generally 85%, unless otherwise specified in the drilling program.

Further analysis is required to determine the neutral point of axial stress for BHA components, e.g. running drilling jars in compression or tension..

### 6.6.2 BHA Stabilisation

The following considerations shall be used to determine the BHA stabilisation configuration to be used:

- When it is desirable to prevent bending moment being carried through to the bit from the BHA above, a packed hole (or stiff) BHA should be selected. This arrangement can be used either in vertical or deviated wells where it is desirable to hold azimuth and inclination.
- In packed hole assemblies, the near bit stabiliser must be full gauge. The first string stabiliser should normally be full gauge. However, under-gauge, first string stabilisers are sometimes used to hold angle in deviated holes where there is a tendency to drop.
- In addition to improving the steerability of the drilling assembly as described above, stabilisers are also important in providing stand-off of the BHA from the wellbore, decreasing the possibility of differential sticking.
- In general, full 360° wall contact stabilisers should be used to prevent gouging the wellbore. In soft formations, integral blade stabilisers are preferred. As formation strength increases, roller reamers may be used to reduce torque.



### 6.6.3 Bottomhole Assemblies

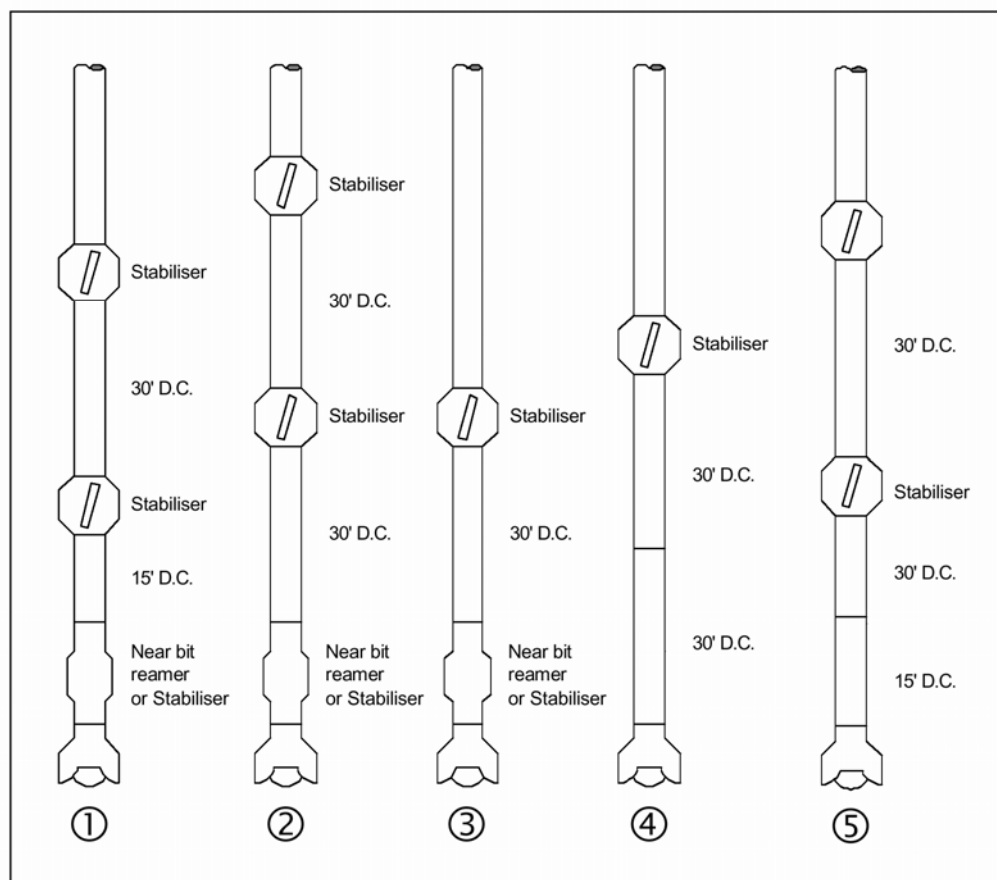
Each generalised configuration of bottomhole assembly shown below represents a typical directional tendency while drilling. The effect of the tendency is dependent on a number of variables, including:

- Formation hardness and bed dip.
- Bit type.
- Stabiliser type and diameter.
- Hole size and drilling parameters, such as weight on bit and rotary speed.

Stabiliser wear in abrasive formations has a significant effect on directional tendency.

The diagram below describes the general stabiliser placements for drilling vertical or directional 8½" hole and 6 1/8" hole.

BHA's for directional wells will be detailed in the Drilling Program for that well. Chapter 3 of this Manual provides more detailed summaries of each BHA configuration.



**Table 30. Standard BHA Configurations in Nominally Vertical Wells**

BHA	17 1/2" Pendulum	12 1/4" Pendulum	8 1/2" Pendulum	8 1/2" Packed	6 1/8" Pendulum	6 1/8" Packed
1	17 1/2" bit	12 1/4" bit	8 1/2" bit	8 1/2" bit	6 1/8" bit	6 1/8" bit
2	2 x 8" DC	8" Motor	6 1/2" Motor	NBRR	4 3/4" Motor	NBRR
3	Stabiliser	2 x 8" DC	6 1/4" DC	6 1/2" motor	4 3/4" DC	4 3/4" Motor
4	1x 8" DC	Stabiliser	Stabiliser	Stabiliser	Stabiliser	Stabiliser
5	11-15 x 6 1/4" DC	1 x 8" DC	20-26 x 6 1/4" DC	6 1/4" DC	20 x 4 3/4" DC	4 3/4" DC
6	6 1/2" Jars	11-20 x 6 1/4" DC	Jars	Stabiliser	Stabiliser	Stabiliser
7	2 x 6 1/4" DC	6 1/2" Jars	2-3 6 1/4" DC	20-26 6 1/4" DC	20 x 4 3/4" DC	20 x 4 3/4" DC
8	6 x 4 1/2" HWDP	2 x 6 1/4" DC	6 x 4 1/2" HWDP	6 1/4" Jars	4 3/4" Jars	4 3/4" Jars
9		6 x 4 1/2" HWDP		3 x 6 1/4" DC	3 x 4 3/4" DC	3 x 4 3/4" DC
10				6 x 4 1/2" HWDP	6 x 3 1/2" HWDP	6 x 3 1/2" HWDP
<b>Comments</b>	Available WOB 25 - 40 klb	Available WOB 25 - 45 klb A mud motor may be run immediately above the bit.	Available bit weight approx 40klb	Available bit weight approx 40 klb.	Available bit weight approx 33 klb.	Available bit weight approx. 34 klb.


**NOTE: Consideration should be given to using a slick BHA when drilling the Diorite commonly found in Tasmania.**

#### 6.6.4 Directional Drilling with Rotary BHAs

The natural tendency for a bit to drill perpendicular to bedding at low to moderate dip angles may be used to reach targets by optimum rig positioning. In areas where formation dip influence and directional surveys are well documented, consideration should be given to moving a drilling pad in order to achieve a tight target tolerance using conventional rotary drilling.

In general, the following shall apply (although specific wells may differ):

- In general rotary BHA's tend to build angle and directional control is maintained by selecting a BHA which gives the desired Build-up Rate (BUR).
- Due to generally strong build tendencies, the Directional Drilling Contractor should err on the low side of the deviated section, as it is generally easier to make a build correction than a drop correction.
- Maximum desired Build Up Rate is normally 2 1/2 to 3 degrees/ 30 m. Dog-Leg Severity is generally 5 degrees/ 30 m.
- The abrasive nature of formations must be considered as stabiliser gauge wear can alter during the course of a bit run. This may change the directional characteristics of the BHA.
- Heavy Weight Drill Pipe (HWDP) and drill pipe must have smooth and flush hardfacing in accordance with API RP7G.

 API RP7G (Specifications for Drill Pipe).

## 6.7 SIDETRACKING

Wells may require side-tracking for various reasons. These include, but are not limited to the following:

- Re-drill the well to a new target.
- Sidetrack past a fish.
- Sidetrack due to hole problems.

The main requirement in sidetracking a well is the development of a lateral force to allow the bit to cut on the side of the hole. This lateral force should be provided by the geometry of the BHA, forcing a cut on the side of the hole. Historically, the most effective BHA configuration to achieve a successful sidetrack kick-off is a mud motor with bent sub or steerable motor. This section provides guidelines and considerations for achieving a successful kick-off.

### 6.7.1 Kick-Off Point Selection

If possible, the kick-off location should be selected so that the formation is softer than the kick-off plug to increase the chances of obtaining a successful kick-off.

If, however, only medium to hard formations exist at the required side-track depth, operational difficulties and time are increased. A controlled ROP should be maintained until confirmation of a successful kick-off is achieved.

### 6.7.2 Kick-Off Plugs

The general requirements for setting sidetrack cement plugs are as follows:

- Cement plugs shall have a minimum length of 90 m in open hole.
- Cement slurry shall be a minimum 16.5ppg, to be confirmed by laboratory testing.
- Cement plugs should be batch mixed, if possible.
- Run a tubing stinger at least equal to the length of the cement plug.
- Consider running a pre-flush prior to balanced cement plugs, at least equal to the weight of the mud.
- A Hi-Vis pill may be spotted below the plug.

The procedure for drilling kick off plugs should be as follows:

1. Pull out of plug slowly.
2. Circulate conventionally to clean string (do not reverse circulate, to avoid traces of cement remaining in the string that may fall onto mud motor when drilling recommences).
3. RIH with mill tooth bit. Wait on cement for a minimum of 12 hours.
4. Dress off 5 m, and weight test the plug.
5. If the cement appears to be hard, RIH mud motor and bent sub. Wait a minimum of 24 hours from pumping cement before attempting to kick-off. Wait longer if necessary to achieve hard cement.
6. If the plug does not show signs of compressive strength, drill and wash through sufficient cement to allow placement of a second 90 m plug at a suitable depth for sidetracking.

### 6.7.3 Casing Windows

When preparing to cut a casing window, the following guidelines should be applied:

- When making the initial cut, care should be taken to avoid casing collars and centralisers.
- The cut should be initiated a minimum of 3 m above a casing collar.
- The lengths of window to facilitate an effective sidetrack are tabulated below:

Casing Size	Minimum Window	Optimum Window
7" Casing	9m (30')	12 m (40')
9 5/8" Casing	10.51 m (35')	15 m (50')

Table 31. General Lengths of Window to Effect a Sidetrack.

### 6.7.4 Sidetracking on the Low Side of the Hole

At commencement of a sidetrack, the low side sidetrack can take off rapidly. As there is a risk of creating high doglegs in this instance, it may be preferable to come off at a low right or low left angle rather than a direct vertical drop off. Once the new hole has been cut, lateral separation should be maintained to prevent collapse of the old hole onto the new.

## **6.8 DIRECTIONAL DRILLING REQUIREMENTS**

The following section provides a series of guidelines and considerations relating to the drilling of high angle or horizontal wells. The guideline and considerations are presented to augment the well design and directional contractor procedures and provide a broad overview of the required practices, procedures and considerations to assist in the maintenance of safe, efficient and cost effective operations whilst drilling high angle and horizontal hole sections.

### **6.8.1 Preparation**

Effective equipment preparation and full dissemination of programme requirements and drilling procedures are essential for the successful completion of high angle and horizontal wells.

#### **1. Daily Briefings**

A routine daily meeting should be held between well site and office to identify potential problem areas, the forward program and logistical requirements for the forthcoming 24hr period.

This section describes the requirements to be considered during directional drilling activities.

### **6.8.2 Kick-Off and Initial Build Selection**

1. An initial kick-off and build section with smooth build rates is required to minimise torque and drag in deeper critical hole sections. The DSV should ensure all personnel are aware of this requirement and that potentially troublesome doglegs are wiped immediately.
2. Excessive doglegs or a drop in build rate have a much greater effect on torque and drag in top hole than in deeper hole sections. Extensive use of torque and drag analysis while drilling shall be made to assess the impact of directional variations on the overall directional operations plan.

### **6.8.3 High Angle/Extended Reach Tangent Sections**

#### **6.8.3.1 Bit Selection**

The choice of bit should take into account the degree of reactive torque produced and the limitations of the motor. For instance some PDC bits can make motor tool face control difficult resulting in erratic hole, increased torque and drag and low ROP's. The use of motor bearing three-cone bits is often preferred for these sections.

The design criteria when selecting three-cone bits are:

- Maximise penetration rate to limit open hole time.
- Extended bearing life to reduce the frequencies of bit trips.
- Bits should be resistant to cone erosion as greater than normal flow rates are required for hole cleaning.
- Enhanced gauge protection on cutters, shank and shirt tail in order to withstand the increased lateral loading when used with steerable systems.

The design criteria when considering PDC bits are:

- Maximise penetration rate to limit open hole time.

- Small cutter size to reduce reactive torque and enhance steering capability.
- High cutter density and gauge studs to limit gauge wear.

#### **6.8.3.2 Hydraulic Requirements & Practice**

Efficient hole cleaning is essential to the success of directional drilling. As such all hydraulic programs should be designed for maximum hole cleaning capability as follows:

- Circulate at the highest possible rate within the constraints of ECD on weak formations. Install a by-pass nozzle on mud motors to increase flow area if necessary.
- Circulate the hole clean (as much as practical) prior to commencing a trip, a minimum of 1.5 times the bottoms up volume is normally required.
- Consider using a hi vis / low vis / hi vis sweep regime to facilitate disturbance and removal of cuttings beds. Keep pipe rotating while pill circulating.
- Apply enhanced monitoring of drilling parameters for increases in torque and drag.
- Perform wiper trips as required.
- Ensure Fann viscometer 6 rpm reading is 1.0 – 1.5 times hole diameter.

#### **6.8.3.3 Casing Wear Monitoring and Prevention.**

- Install 2 ditch magnets in the flowline or possum belly to monitor casing wear. The amount (weight) of recovered shavings should be reported daily.
- HWDP and drill pipe should have smooth hardfacing only.

#### **6.8.3.4 BHA Component Inspections**

All BHA components should have received a full inspection prior to use on a directional well. The complete BHA should be returned for further inspection after completion of the well.

Stress relief grooves are required on all components (including non-magnetic components and jars).

#### **6.8.3.5 Drilling Jars**

Enhanced hydraulic (up/down) short jars should be used. Use of a drilling accelerator or 2 jars should be considered.

## 6.8.4 Final Build and Horizontal Hold Section

### 6.8.4.1 Bit Selection

The criteria for bit selection are identical to those detailed in section 6.8.3 above. The Following figure illustrates the common problems encountered when drilling horizontal hole sections and potential preventative measures relating to bit selection.

PROBLEMS ENCOUNTERED	PREVENTATIVE MEASURES
Side-Loading Using Steerable Systems	Shorten shank or gauge length Increase gauge protection Opt for rotary drilling if possible
High Torque - Reduced Directional Control	Use less aggressive PDC Shorten gauge length of PDC bit Increase Number of gauge cutters Opt for Roller Cone Bit
Difficulty Maintaining Hole Angle	Longer Gauge Length on PDC Bits Lug Pads On Roller Cone Bits Use Steerable system
Excessive Cuttings Bed Generation	Use Lug Pads on Roller Cone Bits Increase gauge cutters on PDC bits (Both measures to facilitate efficient back-reaming operations)
Reduced Bit Life Due To Motor Use	Use PDC Use Motor Bearing Roller Cone Bits Use Low speed PDMs Opt for rotary drilling if directional control allows

**Table 32. Bit Selection Guidelines**

### 6.8.4.2 Drilling Fluids & Hydraulics

As per 6.8.3., item 2.

### 6.8.4.3 Drilling Jars

Two sets of jars can be run. Place one set above the DC's. Place a second set in the cased hole section.

### 6.8.4.4 Drill Pipe Requirements

Drilling horizontal sections places high buckling and torque stresses on the DP. Use of torque and drag analysis is essential to predict actual loads and determine the grade of drill pipe required. Actual requirements and design loads shall be indicated in the Drilling Programme.

Drill pipe should be fully inspected prior to use on high angle or horizontal wells.

### 6.8.4.5 BHA Design

The directional contractor shall use offset well and contractor experience to design the BHA.. The DSV and Directional Drilling Engineer shall base their BHA configurations on those proposed, however modification based on the previous BHA runs will be required. The use of steerable systems which have a neutral tendency in rotary mode are optimum for these hole sections.

#### **6.8.4.6 Casing Wear Monitoring & Prevention**

- Install 2 ditch magnets in the flowline or possum belly to monitor casing wear. The amount (weight) of recovered shavings should be reported twice daily.
- HWDP (and DP rotating within the casing) should have smooth hardfacing only.
- Consideration should be given to using drill pipe casing protectors.

#### **6.8.4.7 Data Recording**

Successful performance in horizontal drilling of wells requires the development of a comprehensive database of experience as optimum practice is often very area specific. As such all personnel should be reminded of the requirement to accurately record all possible data, specifically:

- Drilling parameters used, WOB, RPM, Torque, pressures, circulation rates etc.
- Motor condition, stabiliser wear patterns.
- Mud properties.
- Comparison of predicted vs. actual BHA performance.
- Survey data, toolface control data.
- Hole conditions on trips.
- Formation data, hydrocarbon data (gas compositions ratios etc.).



### 6.8.5 Common Problems and Remedies

Problems commonly encountered in drilling extended reach and horizontal wells are illustrated in the table below.

Problem	Recommended Precautionary Measures
<b>Inefficient Hole Cleaning and Reduced Borehole Stability</b>	<ul style="list-style-type: none"> <li>• Maintain high annular velocity, use turbulent flow pattern wherever possible.</li> <li>• Use low rheology fluid (horizontal sections) 6 rpm = 1.5 to 1.0 x hole size.</li> <li>• Use extended rheology drilling fluids for high angle 12 ¼" and larger hole sections.</li> <li>• Pump in/out of the hole - rotate as much as possible.</li> <li>• Perform frequent wiper trips.</li> <li>• Monitor drilled cuttings for signs of caving.</li> </ul>
<b>Poor Tool Face Control - Weight Stacking</b>	<ul style="list-style-type: none"> <li>• Monitor torque closely.</li> <li>• Use single bend steerable systems.</li> <li>• Drill in rotary mode as much as possible.</li> <li>• Orient after connections.</li> <li>• Use water-melon profile stabilisers.</li> <li>• Minimise heavy BHA components.</li> <li>• Monitor helical buckling of drill pipe in orienting mode.</li> </ul>
<b>Casing Wear - Excessive Torque and Drag</b>	<ul style="list-style-type: none"> <li>• Use minimum HWDP - smooth hardfacing only (also on DP rotating within casing).</li> <li>• Install flowline magnets - record metal filings recovered twice daily.</li> <li>• Record torque values at the shoe on every trip.</li> <li>• Wiper trip at first signs of increasing torque/drag.</li> <li>• Keep BHA as light as possible.</li> <li>• Use non-rotating DP protectors in casing.</li> </ul>
<b>Drill String Failures</b>	<ul style="list-style-type: none"> <li>• Ensure full inspection prior to well.</li> <li>• Perform visual inspection on every trip.</li> <li>• Monitor rotary torque closely.</li> <li>• Ensure adequate back-up equipment availability.</li> <li>• Perform full inspection of drill string after completion of the well.</li> </ul>

**Table 33. Recommended Precautionary Measure for Problems in Drilling Directional Well Sections.**

### 6.8.6 Mudmotor Operating Practices

The following practices should be applied to ensure efficiency of motor operations:

#### a. Surface Checks

- Check the bent sub offset to ensure it is as planned.
- Make up the motor, (MWD if used) and bit. Test the motor and MWD at two or 3 differing flow rates, record circulating pressures and rates.
- Lock the hook and ensure bent sub orientation is tracked while RIH (align the I I scribe mark on the motor with that of the MWD, if used).
- Ensure dump valve installed to avoid tripping out wet.

#### **b. Running In The Hole**

- Check the string is full every 10 stands, or if a float is used, fill the drill pipe every 10 stands.
- Care should be taken when running in open hole. Damage to the motor bearings or bit may occur from hitting hard ledges of formation, particularly with a high angle bent sub.
- Wash down the last stand, gently tag bottom, establish the required tool face before commence drilling.

#### **c. Tripping Out Of The Hole**

- No rotation of the drillstring should occur when using a high angle bent sub (greater than 2 degrees).
- Circulate bottoms up at the shoe where the shoe is at a high angle.

#### **d. Motor At Surface**

- Inspect the body for signs of wear and damage.
- Check the play in the bearing section by manipulation of the bit box on the motor to evaluate bearing wear based on the play and determine if the motor is to be re-run.
- Test the motor at the same flow rates as in the surface test in 1 above and compare resulting circulating pressures. It is normal to see some reduction in pressure as the motor/stator tolerance increases.

### **6.8.7 General Recommendations When Using Motors**

#### **a. Bit Selection**

Select suitable bit and motor combinations. Where PDC bits are used, they should generally have a diamond reinforced gauge of short length (for steerability).

#### **b. Spiral vs. Straight-blade stabilisers**

All stabilisers should have short blade, barrel profiles to reduce wall contact. The difference between spiral and straight blades is formation dependent.

#### **c. High Speed Vs. Low Speed Motors**

In general there is little ROP improvement with faster motors. The shorter, high torque, low speed motors enhance steerability and provide longer bearing life for rock bits.

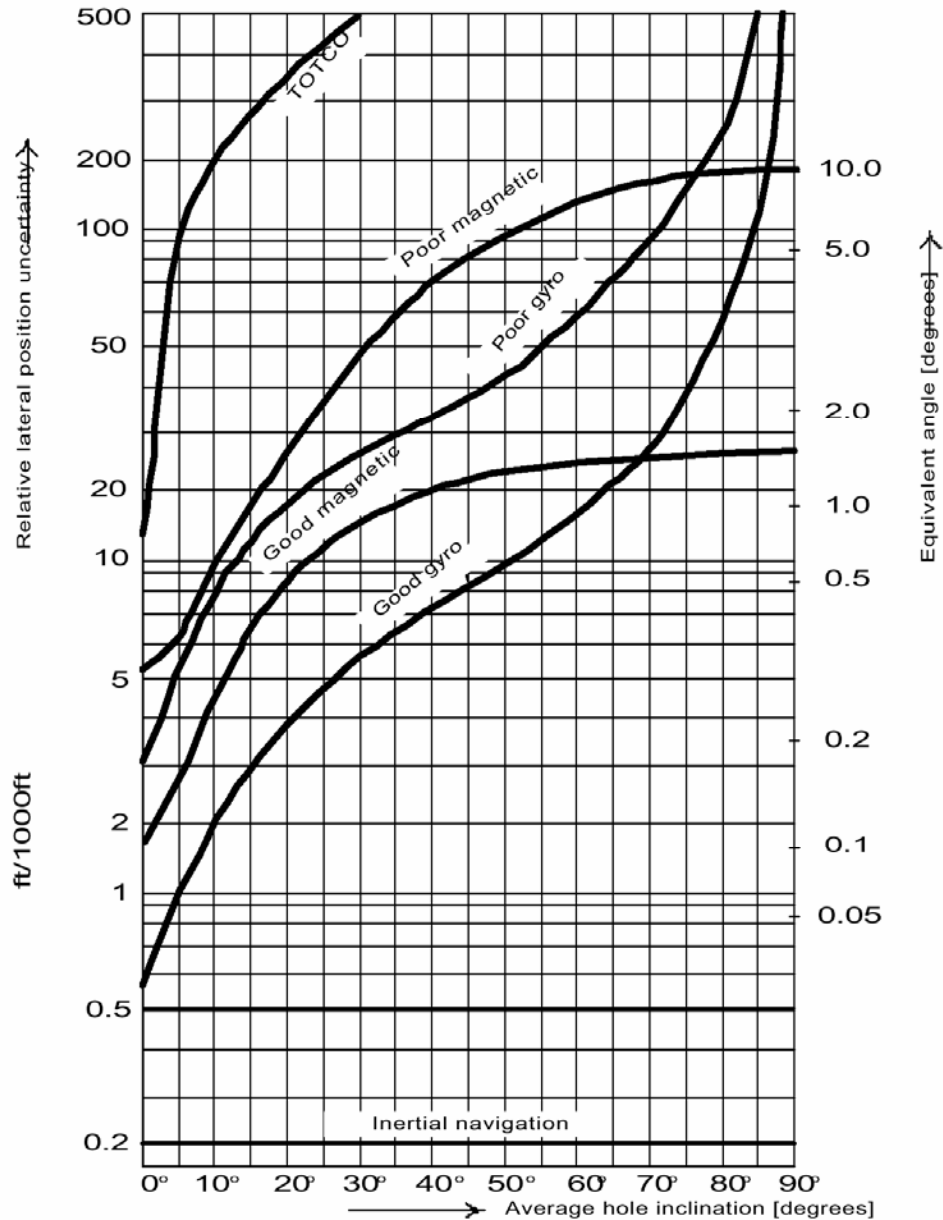
## Appendix I: Lateral Position Uncertainty

The set of curves shown below demonstrate tool comparisons and provide an approximation of the position uncertainty of a well.

The positional estimate is made by dividing the well into sections and using the curves to estimate the uncertainty for each section.

The results are then summed to obtain the total position uncertainty.

A worked example is given after the figure below to demonstrate the application of the curves.



**Figure 5. Lateral position Uncertainty – Tool Comparison**

## Appendix II: Worked Example

The following worked example uses the Lateral Position Uncertainty curves above to demonstrate the approximate positional uncertainty for the well, based on a “good magnetic survey”.

The well is divided into 3 sections (see Simplified Sections of Example Well, overleaf)

- |           |   |
|-----------|---|
| Section 1 | A vertical section from 0 to 550m (1800') AHD.  |
| Section 2 | A tangent section with an inclination of 18.5° from 550m (1800') to the target at 975m (3200'). |
| Section 3 | A tangent section with an inclination of 18.5° from 975 m (3200') to TD at 1143m (3750').       |

The position uncertainty from each section can then be estimated.

### Section 1 (The vertical section from 0 to 550m {1800'})

From the 'good magnetic' curve at 0° inclination, 1.8' per 1000' is obtained.  
The Along Hole depth of this section is 550m {1800'}  
the uncertainty radius is  $(1800/1000) \times 1.8 = 3.2'$  or 0.975m

### Section 2 (The tangent section from 550m to 975 m {1800 to 3200'} AHD)

From the 'good magnetic' curve at 18.5° inclination, 8.25' per 1000' is obtained.  
The Along Hole depth of this section is 975-550m = 425m {3200-1800' = 1400'}  
The uncertainty radius is  $(1400/1000) \times 8.25 = 11.5'$  or 3.505m

### Section 3 (The tangent section from 975m to 1143 m {3200 to 3750'} AHD)

The same uncertainty of 8.25' per 1000' is obtained from the curve.  
The Along Hole depth of this section is 1143-975m = 168m {3750-3200' = 550'}  
The uncertainty radius is  $(550/1000) \times 8.25 = 4.5'$  or 1.372m

### Summation of errors from individual sections

From the above Sections, the position uncertainty at the target will be the uncertainty of Section 1 added to Section 2 =  $3.2 + 11.5 = 14.7'$ , rounded up to 15' (4.48 m).

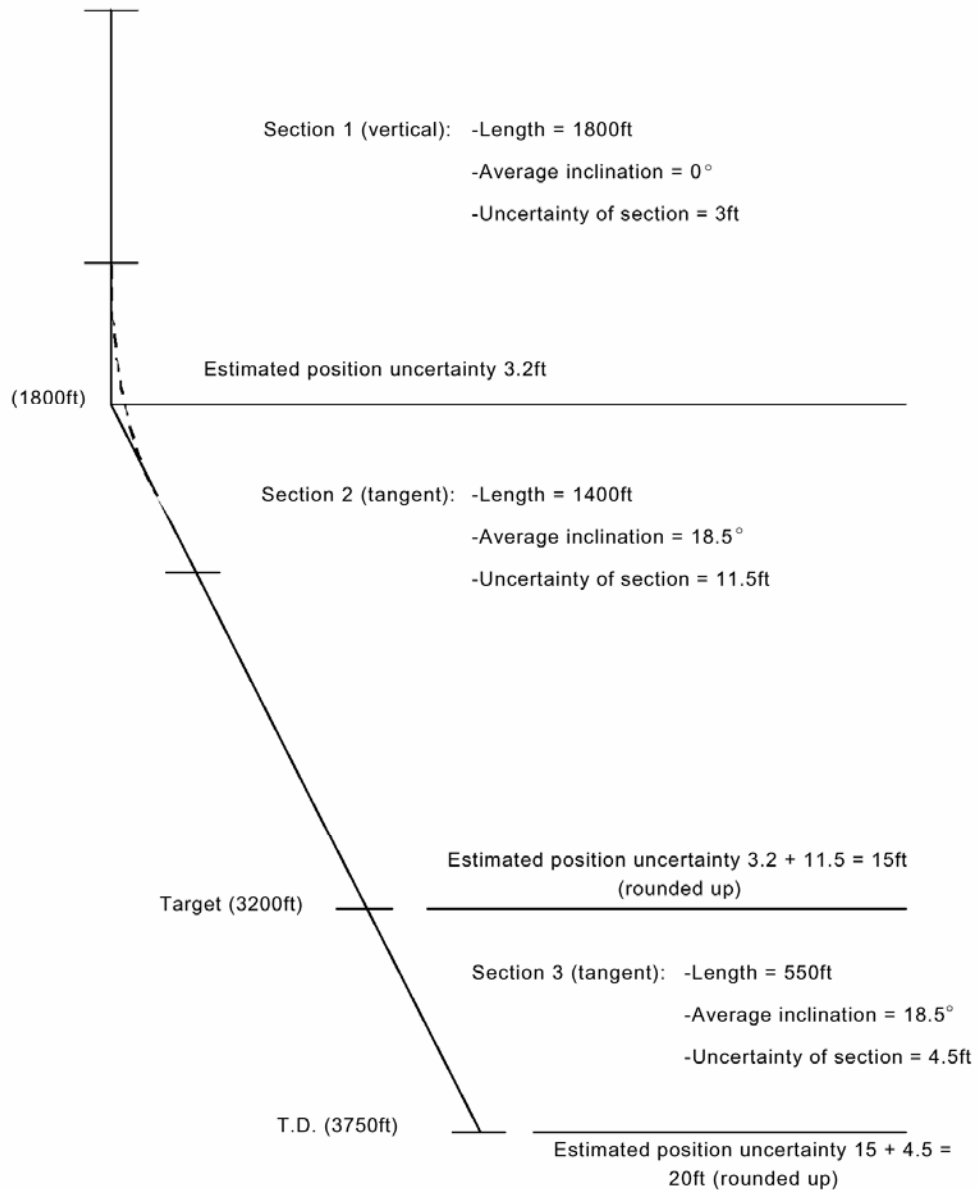
Thus the estimated position uncertainty at the target is a circle with radius 15'. (4.48 m)

At TD the uncertainty will be the uncertainty at the target added to the uncertainty of Section 3 which is  $15 + 4.5 = 19.5'$  rounded up = 20'. (5.94 m)

Thus the estimated position uncertainty at TD, is a circle with radius 20'. (5.94 m)

#### Note:

This method of estimating position uncertainty produces a circle of uncertainty, and should only be used as a guide to possible error. In reality the uncertainty will be an ellipsoid which, when calculated with a computer will give a smaller and better defined position uncertainty of a well. For any work involving well position uncertainty, the ellipsoids should be used.



**Figure 6. Simplified Sections of Example Well**

### Appendix III: Ellipse of Uncertainty

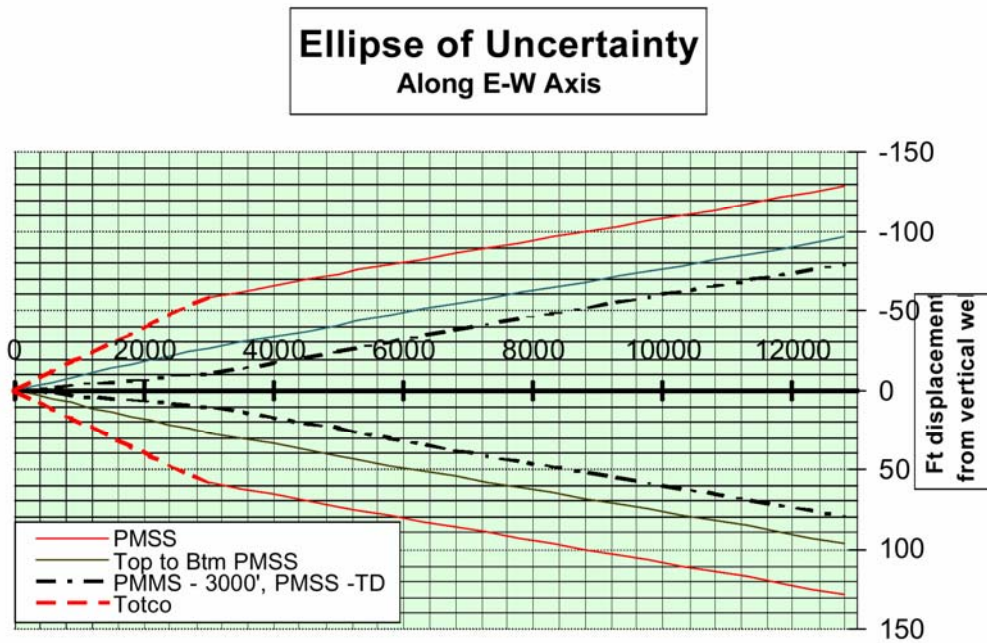


Figure 7. Ellipse of Uncertainty – Along E-W Axis

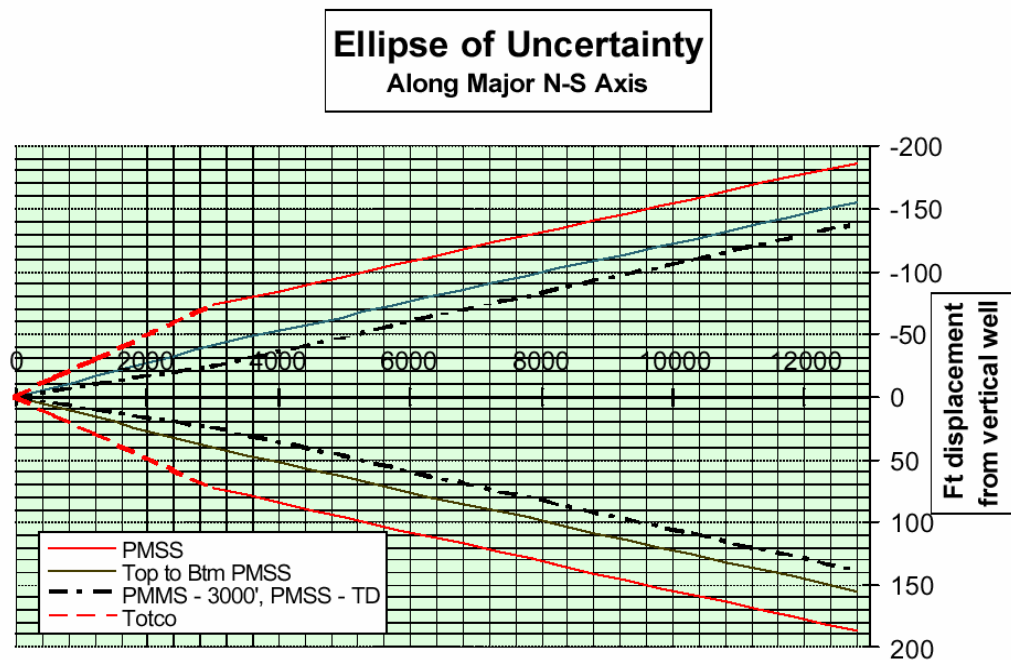


Figure 8. Ellipse of Uncertainty – Along Major N-S Axis

**CHAPTER 7  
CASING**

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## **7.1 OBJECTIVES**

The primary objective of casing operations is to run and subsequently cement a string of casing which is capable of meeting the subsequent pressure test and service requirements for the next hole section and to allow hydrocarbons to be produced and the well fracture stimulated if required.

To achieve this objective, the following must be avoided:

- Damage to the threads that may reduce the sealing capacity, in turn affecting the pressure rating of the string.
- Damage to the body of the casing that may reduce the collapse and burst rating and life expectancy due to ovality or gouges.
- Damage which may affect the drift of the casing due to buckling, crimping or ovality.
- Exceeding pressure test rating safety factors and so affecting the integrity of the casing or well head.
- Measurement or running errors that result in incorrect casing shoe depth.
- Poor hole or drilling fluid conditioning resulting in stuck casing or ultimately a poor cement job.
- Surging the formation by running too quickly, causing mud losses and formation damage.

Whilst handling and running casing personnel shall adhere to the following:

- All casing and handling strings shall be drifted (using a standard API drift, as per API 5CT) on the rig site and accurately measured prior to use.
- Two downhole non-return valves (NRVs) must be included on any casing string to be run through a hydrocarbon-bearing interval.
- Differential-fill float equipment shall not be used on casing strings that are to be run through potential hydrocarbon-bearing zones.
- Mud pit volumes must be monitored when running and cementing casing.
- Casing must be pressure tested prior to drilling out the casing shoetrack.
- The last joint of casing **MUST** be washed down.

Bottom will not be tagged unless the casing is being circulated..



## 7.2 RESPONSIBILITIES

Responsibilities for the preparation, execution and reporting of casing operations are tabulated below.

<b>Task</b>	<b>Performed by</b>	<b>Verified by</b>
Prepare the Casing Design for inclusion in the Drilling Programme	DM	DM
Ensure sufficient casing stocks available	DM	DM
Ensure sufficient casing accessories available	DM	DM
Order casing.	DSV / DM	DM
Order casing accessories.	DSV / DM	DM
Prepare casing for running ( i.e. drift, clean and dope threads)	Drilling Contractor	DSV
Determine placement of centralisers	DM	DM
Prepare casing running program and send to DM prior to running casing	DSV	DM
Make an accurate record of the string as it is installed in the well	DSV	DM
Prepare casing running report	DSV	DM
Condition hole and drilling fluid	Drilling Contractor	DSV, Drilling Fluids Engineer
Conduct a Crew Safety Toolbox Meeting for all personnel involved in the job	Drilling Contractor	DSV
Run and land casing	Drilling Contractor	DSV
Confirm casing tally prior to landing including correct measurement of all joints.	Drilling Contractor	DSV
Inspect casing during running. Ensure it is made-up to the correct torque specifications and run as per running list	Drilling Contractor	DSV
Prepare Casing and Cementing Report Form	DSV	DM
Check that cement and additive shown on casing and cementing report are what was actually run	DSV	DM
Test casing	Drilling Contractor	DSV

**Table 34. Responsibilities for the Preparation, Execution and Reporting of Casing Operations.**

## 7.3 CASING STANDARDS

This section describes the casing standards and requirements to be adhered to by the Drilling Contractor and monitored by the DSV during drilling operations.

### 7.3.1 Casing Types and Functions

The table below illustrates standard nomenclature and functions used by GSLM with reference to casing classification.

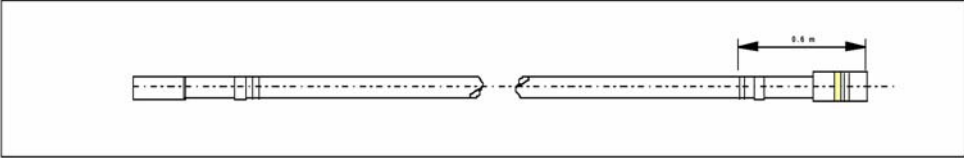
Casing Type	Function
<b>Conductor Pipe</b>	<ul style="list-style-type: none"> <li>Provides structural strength to cover unconsolidated surface formations</li> <li>Serves as a circulating system for the drilling fluid</li> <li>Guides the drilling and subsequent casing strings into the hole</li> </ul>
<b>Surface Casing</b>	<ul style="list-style-type: none"> <li>This string is normally cemented to surface</li> <li>Provides blow-out protection</li> <li>Seals off water aquifers</li> <li>Prevents loss of circulation</li> </ul>
<b>Intermediate Casing</b>	<ul style="list-style-type: none"> <li>Isolates weak formations (sloughing and caving)</li> <li>Cases off loss zones</li> <li>Cases off reservoir formations</li> <li>Provides blow-out protection by upgrading the strength of the well</li> <li>Cement fill is required to isolate hydrocarbon zones.</li> </ul>
<b>Production Casing</b>	<ul style="list-style-type: none"> <li>Separates/ isolates productive zones from other reservoir and non reservoir zones</li> <li>Cement fill is required to isolate hydrocarbon zones.</li> <li>On monoboires the entire open hole annulus should be cemented.</li> </ul>
<b>Liner</b>	<ul style="list-style-type: none"> <li>Separates/ isolates productive zones from other reservoir and non reservoir zones</li> <li>Tied back to previous casing string.</li> <li>Normally cemented back to liner hanger.</li> </ul>

**Table 35. Casing Types and Functions.**

### 7.3.2 Casing Specifications

GSLM shall adopt the standards contained in API 5CT for all casing strings utilised in GSLM's wells. All casing and casing equipment procurements should be checked by the DSV for compliance with these standards.

Casing markings shall conform to API specifications that are detailed in the figure below.

API CASING GRADES IDENTIFICATION COLOUR CODES			
			
	API GRADE	MARKINGS ONE PIPE BODY	MARKINGS ON COUPLING
A P I  S P E C I F I C A T I O N S  5 C T	P-110 P-105	One White Band	White Coupling
	C-95	One Brown Band	Brown Coupling
	C-90 L-80 13Cr	One Purple Band One Red, One Brown and One Yellow Band	Purple Coupling Red Coupling with one Yellow Band
	L-80 9Cr L-80	One Red, One Brown and Two Yellow Bands One Red Band and One Brown Band	Red Coupling with two Yellow Bands Red Coupling with Brown Band or longitudinal stripe
	N-80	One Red Band	Red Coupling
	C-75 13Cr	One Blue Band and One Yellow Band	Blue Coupling with one Yellow Band
	C-75 9Cr	One Blue Band and Two Yellow Bands	Blue Coupling with Two Yellow Bands
	C-75	One Blue Band	Blue Coupling
	K-55 J-55 H-40	Two Green Bands One Green Band No Colour Marking or Block at Manufacturer's Option	Green Coupling Green Coupling No Colour Marking or At Manufacturer's Option

Note:

For pup joints shorter than 1.8 m in length, the entire surface except the threads shall be painted.

API Casing Grade Identification Colour Codes (API SPECIFICATION 5CT)

### 7.3.3 Casing Setting Depth

Unless otherwise stated in the Drilling Program the minimum surface and intermediate casing setting depth is determined by a minimum kick tolerance of **30bbls** of swabbed gas influx taken from the bottom of the open hole with the mud weight in use at the time.

The actual setting depth is determined by evaluating offset well data to make sure the proposed setting depth is in a competent formation and not a loose sand. The actual casing setting depth must also be in accordance with all applicable government regulations.

Suitability of these standard criteria should be assessed during the well design to ensure applicability for the well to be considered. Modifications to the standard should be technically justified and approved by the DM prior to implementation.

### 7.3.4 Casing Design Factors

The following general casing design loading and test criteria shall be used in the casing design for all GSLM wells.

Load Case		Design Factors		
		Burst	Collapse	Tension
Conventional wells	Surface, intermediate and production	1.1	1.0	1.6
Special cases (Air drilling, HPHT, liners etc.)	Case by case	Design assumptions shall be specified		

**Table 37. Casing Design Loading Criteria.**

### 7.3.5 Conductor Pipe

The conductor hole shall be augured and set a **minimum** of 8' below the cellar floor depending on the competency of the formation. If possible at least 3' of clay should be augured before setting the conductor. The conductor shall be cemented in place.

### 7.3.6 Shoe Track Configuration

Shoe track requirements:

- A float shoe shall be installed at the base of the bottom joint, with a float collar installed above either the first or second coupling. Surface and intermediate casing will normally have a two joint shoe track.
- Top and bottom plugs shall be used on all casing strings.
- The float shoe, shoetrack and float collar shall be threadlocked.
- Float equipment shall not be welded on to the casing at any time.

### 7.3.7 Centralisation

The standard centralisation program is shown in the table below. The actual centralisation program will be shown in the drilling program.

Casing String	Centralisation Programme
<b>Surface Casing</b>	<ul style="list-style-type: none"> <li>• 3 m from shoe</li> <li>• Centrally on the second joint</li> <li>• Across the third coupling</li> <li>• First coupling below the conductor.</li> </ul>
<b>Intermediate Casing</b>	<ul style="list-style-type: none"> <li>• 3 m from shoe</li> <li>• Centrally on the second joint</li> <li>• Across the third coupling</li> <li>• One over every fourth casing coupling over water sands</li> <li>• One over every second casing coupling across an interval from 15 m (50') below to 15 m above any potential pay zone</li> </ul>
<b>Production Casing</b>	<ul style="list-style-type: none"> <li>• 3 m from shoe</li> <li>• One over next two casing couplings</li> <li>• One over every second casing coupling across an interval from 15 m (50') below to 15 m above any potential pay zone</li> <li>• One over every second casing coupling over any good porous sand with 15 m overlap</li> <li>• One over the 1st, 3rd and 5th coupling above the intermediate or surface casing shoe</li> </ul>

**Table 38. Minimum Standard Centralisation Program**

Bowspring type centralisers will normally be used. For special projects additional centralisation should be run according to DM instructions..

### 7.3.8 Marker Joint

On intermediate or production casing strings, a marker or pup joint of either equal or greater weight and grade to the highest weight and grade casing used in the string, shall be run no more than 15 m above the pay zone. The position of the marker joints must be shown on the casing tally. Only one marker joint is required if pay zones are within 60 m of each other.

## 7.4 CASING PREPARATION

This section describes the safety, transportation and handling of casing before running.

### 7.4.1 Safety

All personnel must be informed of, and observe the following safety and environmental requirements for handling casing:

- Hold a pre job safety meeting before running any casing string.
- Never walk under loads suspended in the elevators or high line.
- Always wear gloves and eye protection when cleaning joints.
- Never get between loads and another object.
- Be careful when rolling casing across racks ensuring that feet do not get trapped.
- **Diesel oil MUST NOT be used for cleaning threads.** The preferred method is to use a high pressure wash system..

### 7.4.2 Transportation of Casing

Tubulars shall only be moved and transported with both thread protectors correctly installed. Road transportation and casing handling are described below.

#### 7.4.2.1 Road Transportation

- GSLM require that all casing loads must conform to all road regulations at all times. This includes both load limits (weight, size etc) and drivers hours. If casing is needed urgently then two drivers may be required. GSLM also require that all trucks must be roadworthy.
- Pipe shall be loaded on bolsters and chained down at each end (and middle for long tubulars).
- Tubulars shall be loaded with all couplings at one end of the truck.
- Pipes shall be loaded to prevent chafing of adjacent couplings.
- After a short distance traveled, chains loosened by load settling must be re-tightened.

#### 7.4.2.2 Handling Practices

- Casing ends should all be easily accessible. This is a primary requirement for the thread-cleaning crew. Move casing only when thread protectors are in place.
- If pipes are to be unloaded by hand via ramps, they shall be rolled in a controlled manner using rope slings to prevent them from gaining momentum. Thread damage can easily occur if pipes strike each other end to end, even with thread protectors installed.
- Use a spreader-bar and choker-chain arrangement near each end of a joint to prevent crushing when handling bundles of casing joints with a crane.
- Store or rack casing only on wooden or metal surfaces free of rocks, sand or other debris.
- Pipe rack arrangements should allow for any programmed wellsite casing inspection. An extra pipe rack may be needed to achieve this.

### 7.4.3 Surface Preparation of Casing

It is the responsibility of the DSV to ensure that all casing and equipment is ordered and is at the wellsite prior to the casing job. It is the responsibility of the DSV to ensure all casing and casing equipment has the correct threads.

The following generic procedure should be followed for preparing casing:

1. Back off the protectors sufficiently to obtain the proper measuring point after each row is laid out.
2. Measure the casing. Write the numbers and lengths clearly in white or yellow on each joint.
3. Count the total number of joints and compare this number with the pipe tally and shipping manifest. As an additional check, calculate the average joint length.
4. Calculate if there is enough casing by checking the pipe tally. Where a mixed string is to be run, the DSV shall verify that sufficient casing of each type is at the wellsite.

**Note:** In general there should be a minimum of five excess joints of surface casing, and ten of production casing in each weight and grade available on the location.

5. Check the weight, grade, and connections of all pipe and accessories are correct as specified in the Drilling Program (see colour coding in Section 7.3.2).

**Note:** All threaded accessories shall be made up on casing pin ends to ease fishing operations in case the casing should fall into the hole.

6. Thoroughly clean, check and lubricate all threads. **Diesel oil must not be used.** A high pressure (fresh) water gun should be used to clean the threads. Connections must be thoroughly dried to prevent subsequent corrosion.
7. Drift with the appropriate API drift. (API 5CT Section 6.9). Mark any failures clearly with red paint.
8. Ensure the thread protectors are clean and reinstall on the pin and box ends (hand tight).
9. Make up the final Casing Tally and Running sheets and send to the DM  
The running list must show:
  - The top and bottom depth of each joint.
  - Where centralisers are to be attached.
  - Where cement basket, if required, is to be attached.
  - Exactly which joints shall be run and which joints shall be left out of the string.
  - The placement of shoe and collar, and special casing equipment.
  - The appropriate length of landing joint to be calculated to ensure a safe working height for the cement head.

When preparing the running list of this type, it is important to specify the position of accessories separately from the joints to which they are attached to avoid confusion over exact location.

A copy of the API Specification 5CT should be available on all drilling rigs and in the GSLM office for reference.

 API Specification 5CT

#### 7.4.4 Equipment Preparation

The following checks must be made to ensure that all the required equipment is at the wellsite, that it is certified (if applicable) and in good working/mechanical order.

Casing Equipment Checklist	Check
Dates of all lifting gear certificates checked.	
Single joint and side door elevators tested on several joints of casing to ensure their fit.	
Side door elevators checked for uneven wear on the bearing surface and for correct operation of the door latch.	
Spider and elevator slips and guides checked for size, condition, and the ability to operate evenly.	
Drilling line condition and load capabilities checked (slip and cut whilst out at the shoe on the last out if required).	
Mud pumps fitted with the proper size liners and in good mechanical condition.	
The mud pump relief valves tested and set.	
Low pressure mud fill line rigged up with a quick opening valve for high rate casing fill requirements	
Power and conventional casing tongs checked for condition of dies and operation	
Stabbing board safety checks carried out according to the Drilling Contractors safety checklist.	
Cementing accessories, shoe, float, stage equipment, cementing stinger, etc. checked for compatibility and suitability.	
Cementing crews and cement is correct before running casing.	
Pipe rams dressed with the correct size casing rams and BOP bonnet seals pressure tested.	

**Table 39. Generic Casing Equipment Checklist.**



## 7.5 RUNNING CASING

The following information is general and should be used by the DSV and Drilling Contractor in preparation of the work instructions for running casing.

### 7.5.1 Conditioning the Hole

Before running casing the hole shall be conditioned as shown in the procedure below:

1. Before pulling out of the hole for casing, the hole must be circulated clean and the drilling fluid parameters checked.
2. The hole depth should be checked by strapping out of the hole and checked against the Casing Tally and Running sheets.
3. A wiper trip may be necessary before running casing if there are indications of hole problems.

### 7.5.2 Running Casing Pre-Job Check List

The following list identifies the key points to be checked by the DSV prior to running casing.

Running Casing Pre-job Checklist	Check
<b>Bradenhead</b>	
<ul style="list-style-type: none"> <li>• Check wellhead threads are compatible with the casing being run.</li> <li>• Check condition of wellhead threads regardless of new or reconditioned wellhead</li> </ul>	
<b>Casing and cement calculations completed and checked</b>	
<ul style="list-style-type: none"> <li>• Correct number of joints of the correct weight and grade included</li> <li>• Shoe track and rat hole as per program</li> <li>• Casing tally and running list prepared. Running list faxed to DM.</li> </ul>	
<b>Landing string drifted and checked</b>	
<b>Cement equipment as follows checked by Cementing Contractor</b>	
<ul style="list-style-type: none"> <li>• Cement head casing connection</li> <li>• Top and bottom plugs installed as appropriate,. Note a ball may be used below the top plug in 3 ½" tubing</li> <li>• Installation witnessed and checked by DSV</li> <li>• Float shoe and float collar installed and checked</li> </ul>	
<b>Centralisers, cement basket, stop collars and pins on rig floor</b>	
<b>Casing running equipment rigged up / on rig floor</b>	
<ul style="list-style-type: none"> <li>• Power tongs</li> <li>• Pick up elevators</li> <li>• Casing elevators</li> <li>• Hand slips</li> <li>• Klampons</li> <li>• Circulating head for all types of casing being run. Check threads compatible with casing</li> <li>• Spider slips (if required)</li> <li>• Spider elevators (if required)</li> <li>• Torque turn equipment (if required)</li> </ul>	
<b>Thread lock and casing compound on rig floor</b>	
<b>Snub and back up lines correctly installed and checked</b>	
<b>Stabbing board checked by stabber</b>	
<b>Drill floor cleared of unnecessary equipment</b>	
<b>Crew safety toolbox meeting conducted</b>	
<b>Surge / swab calculations completed as required</b>	

Table 40. Running Casing Pre-job Checklist.

### 7.5.3 Picking-Up and Running

The following generic checklist should be used by the DSV for running casing, and for writing and checking specific work procedures to be issued to the Drilling Contractor.

Casing Running Checklist Generic	Check
Visually check all joints of casing to ensure that all joints are clear of foreign matter. Ensure 'auto fill' equipment not fitted	
Check casing float equipment after the shoetrack is run in to ensure the float is holding and that circulation is possible.	
Install centralisers in accordance with requirements	
Partially fill each joint and completely fill every five joints	
Make up the connections in accordance with API 5CT.	
If required install a short joint in the intermediate or production casing just above the hydrocarbon zone to assist later correlation	
Before landing the casing, count the joints of casing remaining on location	
Install cement basket approximately 60' below the rotary table on surface casing jobs (if required)	
The last joint must be circulated down – do not tag bottom.	
Set the casing such that it is at a safe height for installing the cementing head, i.e. 4 - 6' above the rig floor if possible	
Circulate a minimum of twice the annular volume prior to cementing. The Yield Point may be lowered if required as to enhance mud displacement efficiency during the cement job. This will be specified in the <b>Drilling Program</b> .	
Reciprocate casing while circulating and cementing if possible	
Landing joint (where run) shall be backed off in the presence of the Toolpusher and Drilling Supervisor.	
Ensure that the next joint is not backing off with the landing joint.	
Ensure that the last collar is soft broken prior to running, unless a double pin crossover is to be used to install the bradenhead.	

**Table 41. Generic Casing Running Checklist**

**Note\*:** Use a casing cover where appropriate to prevent foreign matter entering whilst running the casing. Casing dope shall be applied while the casing is on the V-Door.

**Note\*\*:** When threadlocking is carried out care must be taken to ensure that both pin and box are clean and dry. The thread lock compound shall only be placed on the pin of the connection.

Casing should be run smoothly, in accordance with the running list, avoiding high acceleration and deceleration that could cause unnecessary surge/swab pressures causing the well to swab in or the formation to break down.

Regulate the casing lowering speed to 30 sec/joint or to the optimum speed as dictated by pressure surge/swab calculations. Returns must be monitored constantly.

**Note:**

- Returns should be made to the same tank as is used for filling and a trip sheet filled in.
- When using side door elevators, avoid impact loading which can open the elevator.

 API Specification 5CT.

## 7.5.4 Stuck Casing

### 7.5.4.1 Setting the Casing High

If the casing string becomes stuck during running in and cannot be freed, the safety of the well and casing string design become adversely affected and the following possibilities must be considered:

- a. If the shoe is near the intended setting depth and is located in a suitable formation, the casing can usually be cemented in place and serve its original purpose. The cementing proposals and subsequent casing depths shall be amended and approved by the DM. Emergency hanger and seal assemblies may have to be employed.
- b. There is a possibility that an extra casing string may have to be run to serve the intended purpose of the stuck casing.
- c. Where a casing string contains different weights and grades, the casing design factors must be checked for the new setting depth. A re-evaluation of the design applicability must be performed by the DM.
- d. A non-planned position of the casing collars with respect to the well head slip profiles may be critical. Procedures for installing a (standard) slip and seal assembly are complicated in the following cases:
  - i. There is a collar in the way between the rotary table and the wellhead.  
In this case, after cementing the casing, the BOP can be lifted and the slip and seal assembly installed around the pipe below the obstructing collar.
  - ii. There is a collar located in the landing area of the wellhead.  
In this case, the pipe may either have to be slacked off allowing the slip and seal assembly to be lowered through the BOP stack. Alternatively the pipe may have to be stretched and the BOP stack lifted to install the slip and seal assembly after the casing has been cemented.

In both cases, the pipe will have to be mechanically cut at the proper height to ensure that there is sufficient length of casing above the hanger to allow normal installation of the seal assembly and that the casing stub is sufficiently long to provide sealing into the next wellhead or tubing spool.

If losses have been observed during the cement job and there could be hydrocarbons present, the BOP shall not be lifted without first establishing there is an annular barrier, or by lowering the slip and seal assembly through the BOP stack.

### 7.5.4.2 Allowable Pull on Casing

When pulling on casing, the maximum total surface load on the casing shall not exceed the lesser of either:

- a. 
$$\frac{\text{The lesser of pipe body yield strength or thread yield strength (of top pipe)}}{1.6}$$
- or:
- b. 
$$\frac{\text{The lesser of the weakest pipe or thread} + \text{Weight in air of casing above it}}{1.6}.$$

The following reports are to be submitted to the DM by the first reporting day after completion of cementation:

- Casing and Cementing Report. Casing landing weights must be shown on this form.
- Casing Tally and Running sheets (these should be sent to the DM for checking prior to the casing being run).
- Wellhead Installation Report.

Additional reports as required to explain abnormal or unusual events.

## **7.6 CASING PRESSURE TESTS**

All components of a casing/wellhead system shall be pressure tested in compliance with the standards in Chapter 10 of this Manual. The casing string shall be tested to the **lowest** value dictated by the following:

- The casing design pressure or 80% of the casing burst.
- The wellhead design pressure (3000 psi or 5000 psi).
- The working rating of the BOP.
- Cement head working pressure rating.
- Float equipment manufacturers test pressure limitation.
- Maximum anticipated surface pressure.

The test pressure and the justification for this pressure shall be clearly indicated in the Drilling Program.

## **CHAPTER 8 CEMENTATION**

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## 8.1 OBJECTIVES

The objectives of cementation are to:

- Support and centralise the casing.
- Prevent corrosion of the casing from formation and annular fluids.
- Prevent fluid migration in the annular space between the casing and formation.
- Prevent mixing of water from different aquifers
- Isolate hydrocarbon zones.
- Seal off permeable zones for well abandonment.
- Provide a hard kick off plug for sidetracking existing well track.
- Ensure all regulatory requirements are met.

The following must be followed to ensure a quality cement job:

- Cement slurries must be tested under simulated down hole conditions using samples of water to be used in the cement job. Samples of cement and additives must be taken from the same batch number as the chemicals that went to the site.
- Cementing operations must be carefully planned and controlled to select the correct slurry and to calculate the correct volumes and critical flow regimes required for hole cleaning.
- Slurry and displacement volumes for balancing cement plugs must be carefully calculated to avoid backflow and incorrect placement.
- The drilling fluid and wellbore must be circulated and conditioned before starting cementing operations, to remove cuttings and gas, and ensure optimum rheology for cement placement.
- Mixing, pumping and displacement operations must be monitored to verify volumes are correct and cement slurries are homogeneous.
- Spacers will be used where applicable to avoid contamination.

The following will be used to verify the quality of a cement job:

- Where applicable cement plugs shall be weight or pressure tested.
- A minimum of three samples of each slurry type shall be taken during the cement job.
- A pumping pressure plot of the cement job on Intermediate and Production Casing cementations.
- Cement bond logs may also be run.

## 8.2 RESPONSIBILITIES

The responsibilities for cementing operations are tabulated below. It should be noted that the specification for each cement job is contained in the Drilling Programme and the DSV shall mobilise the materials and co-ordinate with the Drilling Contractor and Cementing Contractor at the well site.

Task	Performed by	Verified by
Finalise cementing specifications	DM	DM
Prepare detailed work instructions	DSV	DM
Collect water sample	Cementing Contractor	DSV
Test samples and prepare recipe	Cementing Contractor	DM
Prepare well for cementing	Drilling Contractor	DSV
Mix, pump and displace cement	Cementing Contractor / Drilling Contractor	DSV
Conduct rig floor operations	Drilling Contractor / Cementing Contractor	DSV
Prepare end of job reports	Cement Contractor / DSV	DSV

**Table 42. Responsibilities for Cementing Operations**

The detailed responsibilities for the execution of cementing operations are presented in the following checklist

Prior to job	Description	DSV	Drilling Contractor	Cement Contractor
3-5 days	Send sample of mixing water to the cementing contractor's Laboratory (not required if using Demin water).	X		
2 days	Verify that mix water quality is acceptable			X
2 days	Check Frac tank volume and order water for cement job.	X		
2 days	Confirm BHST from logs. Notify DM if BHST from logs different than that in the Drilling Program.	X		
1 – 2 days	Order Cement	X		
1 day	Receive Contractors Cement Test Report with recipe for cement and spacer from DM.			
1 day	Prepare detailed procedures and work instructions based on final specifications.	X		
1 day	Check chemicals quality and quantity	X		X
1 day	Calculate cement volumes.	X		X
12 hours	Allocate tasks and agree step by step program	X		
12 hours	Complete mix water and spacer checklist			X
12 hours	Check rig equipment (mud pumps, tanks and lines)		X	
12 hours	Check cement equipment (cement unit, head and lines)			
12 hours	Pressure test cementing unit to 500 psi level above expected working pressure	X		
6 hours	Check wiper plugs installed correctly in the cement head	X		X
6 hours	Check safety equipment (dust mask, goggles, earplugs, gloves, eye wash, fire fighting)		X	
1 hour	Attend Pre-job Meeting	X	X	X
	Check hole clean, losses cured, overbalance sufficient	X	X	
	Check mud rheology is within specification and mud mobility in annulus maximised	X		
	Ensure mud tanks lined up to the cement unit		X	
	Ensure lines pressure tested		X	X
	Complete checklist and verify	X		
	Check water quality from tank prior to mixing cement			X

**Table 43. Detailed Responsibilities for the Execution of Cementing Operations**



### 8.3 CEMENTING INGREDIENTS

This section describes the typical ingredients of cement slurries used by GSLM.

#### 8.3.1 Cement

Cement shall be manufactured in accordance with API Specification 10A. The following cement types are in standard use for all GSLM operations:

- Class G or Class G cement with 35% silica flour (HTB – High Temperature Blend) may be used with appropriate additives for all jobs other than surface casing jobs.
- Class G or class A cement (whichever is specified in the drilling program) shall be used for surface casing jobs.
- Class A Cement shall be used to cement the conductor.

 API Specification 10A, Well Cements, 21st Edition, September 1995.

#### 8.3.2 Additives

Additives and slurry tests shall conform to API Specification 10, Materials and Testing for Well Cements. The various generic additive types used by GSLM are listed below:

- Accelerators.
- Retarders.
- Low density additives (eg Bentonite).
- Friction reducers: dispersants.
- Fluid loss control additives.
- Defoamers and antifoams.
- Gas migration materials.
- Light weight additives (eg Spherelite)
- Lost Circulation Material (Mica etc.)

 API Specification 10, Materials and Well Testing, January 1982.

#### 8.3.3 Mixing Water

The table below indicates the maximum contaminant concentration and pH for cement mixing water. Levels above these limits will significantly affect cement additive performance.

Measured Concentration	Allowable Concentration
Cl-	< 7000 ppm
Na, K	< 5000 ppm
Ca	< 500 ppm
Mg	< 300 ppm
Fe	< 300 ppm
Ba	< 300 ppm
SO4-	< 2000 ppm
CO3-	< 100 ppm
HCO3-	< 500 ppm
Dissolved Organics	< 0.02 %
pH	6 - 8

**Table 44. Allowable Water Contaminants**

## 8.4 CEMENT SLURRY COMPOSITIONS

### 8.4.1 Standard Slurries

The following table below give some examples of the types of slurries that may be used in GSLM wells. Actual slurry requirements shall be specified in the Drilling Program and cement program.

Job Type		Cement type / Additives	Est. BHT °F	Slurry Density Lb/gal	Slurry Yield ft <sup>3</sup> /sk	Mix Water gal/sx	Unconfined Compress. Strength	Coverage	Excess	Preflush / Spacers	Displacement Fluid
Conductor (All wells)		Class A with 1-2%CaCl <sub>2</sub>	70	15.8	1.18	5.2		To cellar floor	N/A	N/A	N/A
<b>Surface Casing</b>											
Surface Casing	Lead	Class A or G plus Spherelite and Bentonite		11.0	2.81	13.15	500 psi	To surface	Gauge + 70%	40 bbl fresh water	
	Tail	Class A or G	220	15.8	1.16	5.01	4,000 psi	120 m above shoe	Gauge + 30%		Mud
<b>Intermediate &amp; Production Csg</b>											
Intermediate and Production Casing (BHT < 230°F)	Lead	Class G plus bentonite		12.8	2.11	11.78		150 m into previous casing	Gauge + 20% or Caliper + 10%	10 Bbl Dual Spacer, 40 bbl SAPP, 10 Bbl Dual Spacer	
	Tail	Class G	<230 °F	15.8	1.16	5.01	4,000 psi	Min 60m above Hydrocarbons			Interm'd: Mud Prod'n: Brine
Intermediate and Production Casing (BHT > 230°F)	Lead	Class G plus bentonite		12.8	2.11	11.78		150 m into previous casing	Gauge + 20% or Caliper + 10%	10 Bbl Dual Spacer 40 bbl SAPP, 10 Bbl Dual Spacer	
	Tail	Class G plus silica flour	>230 °F	15.6	1.56	6.66	4500 psi	Min 60m above Hydrocarbons			Interm'd: Mud Prod'n: Brine

**Table 45. Guide to Standard Cement Slurries**

## 8.5 SPACERS


Spacers for cement placement are required to prevent contamination of the cement slurry by the drilling fluid. The table below provides an overview of their formulation.

Displacement	Formulation
High Annular Velocity Slurry Displacements	<ul style="list-style-type: none"> <li>• A pre-flush brine shall be used prior to cementing the production / intermediate casing / liner.</li> <li>• Spacer will be treated with biocide and will be at a density greater than or equal to mud in the hole prior to cementing.</li> <li>• Spacer volume shall be sized to allow a minimum of 5 minutes contact time with the borehole during displacement and occupy a minimum of 450m of annular volume.</li> <li>• SAPP flush at concentration of 5 kg / bbl shall be mixed with lease water and treated with Biocide at 2 litres / bbl.</li> </ul>
Cement Plug Displacement	<ul style="list-style-type: none"> <li>• A pre-flush brine shall be used prior to cementing.</li> <li>• The spacer density shall be greater than or equal to mud in the hole prior to cementing.</li> </ul>
Scavenger Slurry's	<ul style="list-style-type: none"> <li>• A cement retarder shall be added to the mix water to prevent fast setting of the slurry</li> <li>• Scavenger density shall be between the mud density and the main slurry density. Maximum scavenger slurry density will be 12.0 ppg.</li> </ul>
Oil based mud	<ul style="list-style-type: none"> <li>• No SAPP spacer</li> <li>• Use a specially formulated oil based compatible spacer (normally base oil).</li> <li>• Enable recovery of oil based mud from behind the casing</li> </ul>

**Table 46. Spacer Formulations.**

## 8.6 SAMPLING AND LABORATORY TESTING

All slurry compositions shall be tested at the Cementing Contractor's laboratory to API Specification 10 and reported to the DM and DSV using an approved contractors form.

 API Specification 10, Materials and Well Testing, January 1982.

### 8.6.1 Sampling Requirements

The following sampling requirements must be adhered to by the Cementing Contractor:

- Samples of the mix water from the current well shall be used.
- Samples of additives shall be taken from the same batch number to be used in the cement job.
- It is essential that the cement sample is representative of the dry cement batch sent to the site, or the cement that will actually be used on the job (site sample).
- Samples of all products, including a 10 litre sample of the mix water, may be taken during the cement job and sent to the Laboratory for post-job testing (if required).
- Samples shall be properly packaged in clean containers supplied by the cementing contractor (do not use cordial bottles etc.) as detailed in the table below. Containers shall be airtight as exposure to humidity could affect test results.
- A water quality check shall be performed by the Drilling Fluids Engineer at the rigsite, immediately before the cement job.

Material	Container
Cement and powdered additives	Airtight plastic bag inside metal can with tightly fitting lid
Mix water and liquid additives	10 litre plastic can supplied by cementing company

**Table 47. Sample Packaging.**

### 8.6.2 Sample Quantities

Samples of mix water and other materials shall be provided in the quantities detailed below.

Material	Quantity
Cement	5 kg
Mix water	10 litres
Powdered additives	1 x 300 ml plastic bag (full) per additive
Liquid additives	0.5 litres
Bentonite	1 kg

**Table 48. Sample Quantities.**

### 8.6.3 Sample Labels

The following details must be attached to all cement samples:

- \* Rig name.
- \* Date sample taken.
- \* Type of cementation planned (e.g. [specify] casing, abandonment plugs, etc.).
- \* Name of mix water source (e.g. [name] bore, Cooper Creek etc.).
- \* Where sample was taken from (e.g. Frac. tank, Turkeys nest).
- \* Well name and number.
- \* Expected date of first cementation.

## 8.7 CEMENT COVERAGE

### 8.7.1 Annular Coverage of Cement

The cement coverage standards are outlined in the table below.

Cementation	Top of lead	Top of tail	Excess
Conductor casing	Surface	Fill entire annulus with hard, compact cement.	To cellar floor
Surface casing	Surface	Minimum 120m above shoe. A top up job shall always be run.	Lead 70% min excess on gauge hole. Tail 30% excess
Intermediate / Production casing	150m into previous casing shoe	Minimum 120m of tail or to min 60m above top of hydrocarbon bearing reservoirs.	Gauge hole + 20% excess or <b>Caliper log +10% excess</b>
Liner	Top of liner lap	Minimum 120m of tail or to min 60m above top of hydrocarbon-bearing reservoirs.	Gauge hole + 20% excess or <b>Caliper log +10% excess</b> (lead and tail)

**Table 49. Minimum Annular Cement Coverage Standards**

Variations to the standards above must be specified in the Drilling Program. These may be required to:

- Prevent buckling of the uncemented section of casing.
- Seal off overpressured water sands.
- Seal off water-bearing sands that are depleted or expected to become depleted in future.
- Cement off all potable water zones.

### 8.7.2 Corrosion Protection

To prevent corrosion:

1. The fluid in the annular space between casing strings shall be treated with Biocide in accordance with the following guidelines:
  - Biocide shall be added to any fluid left in the annulus.
  - The concentration of Biocide shall be 1,000 ppm (2 litres/ per 10 bbls of fluid).
2. Displacement fluid may contain inhibitor as specified in the drilling program.

## 8.8 PRIMARY CEMENTING PROCEDURES

The generic procedures given in this Section for cementing casing strings should be used to formulate, verify and check the detailed program.

### 8.8.1 Conditioning the Hole Prior to Cementing

Prior to cementing, the following steps must be performed to condition the mud and the hole:

- Before running casing, the hole must be circulated clean.
- When breaking circulation with casing on or near bottom, start circulating at low rate and gradually increase rate once returns are established.
- Once casing is on bottom the mud may be conditioned to improve displacement efficiency. This can be done by adding dispersants / thinners to reduce the Yield Point and 10 minute gel strength to minimum practical levels (preferably 2/3). In general YP for 12 1/4" x 9 5/8" to be below 16, for 8 1/2" x 7" to be below 14, for 6 1/8" x 3 1/2" to be below 10.  
**Do not use SAPP** to reduce YP, use lignosulphonate and caustic (or equivalent).
- The mud shall be circulated until gas values are low and stable and the programmed mud rheology obtained.
- Prior to the job circulate a minimum of 120% of the casing contents and continue circulating until the returns are clean to ensure that there is no foreign material in the casing and that the annulus will not pack off with cuttings.
- Annular velocity whilst circulating shall be no greater than whilst drilling.

#### Notes:

1. Record circulation pressure at the rate that will be used to displace the cement, in order to determine differential pressure and thus estimate the top of cement (TOC).
2. If losses are observed below the rate required to give an annular velocity high enough to meet the displacement requirements, consideration should be given to circulating around a LCM pill. This should be carried out at a rate where slight losses are induced.
3. Cement should be displaced at 95% of the maximum rate achieved without incurring losses.
4. The DSV should calculate the estimated ECD for different circulation rates and determine the likelihood of any potential losses.

### 8.8.2 Conductor Casing Cementing Procedures (if not pre-set)

The following procedure shall be adhered to during conductor casing cementation:

1. Mix the slurry and pour it into the annular space outside the conductor.
2. Trammel with a pole to ensure the annular space is completely filled with cement.

### 8.8.3 Surface / Intermediate / Production Casing Cementing Procedures

The following procedure shall be adhered to during surface, intermediate and production casing cementation:

1. For logged Intermediate and Production holes, confirm BHT from logs and compare with programmed BHT, notify DM immediately of any significant difference.
2. Calculate cement volumes. For surface casing use theoretical hole volume + 70% for the lead and hole volume + 30% for the tail (Refer to Drilling Program for required excess). For intermediate and production hole use caliper +10%. If caliper log data not available use a minimum of theoretical hole volume +20% excess.
3. Check mixwater requirement and ensure sufficient supplies are on location. Check quality of mixwater.
4. Hold pre job safety meeting.
5. Rig up cement lines, flush with water and pressure test to 500 psi above burst pressure of casing.
6. Pump spacer (if required).
7. Drop the bottom plug (if programmed).
8. Mix and pump the cement slurry.  
Close valve at cement head and flush lines with water via an upstream Tee.
9. Drop the top plug.
10. Displace the cement slurry. This can be done either using the rig pumps and switching back to cementing contractor for last 5 bbls or by the cementing contractor. Do not exceed 8 bpm during displacement. For displacements carried out by the Cementing Contractor, the displacement tanks shall be used.  
**Note:** During displacement, monitor the returns closely to ensure there are no losses. If unacceptable losses are encountered, reduce the pump rate in increments of ¼ barrel per minute until returns are regained.
11. For the last 5 - 10% of displacement volume before bumping the plug, slow the pumps down to 1/4 - ½ of displacement rate and record this pressure. This final displacement pressure shall be used for calculating the estimated TOC. Record final displacement pressure on casing/cement report.
12. Bump plug and record bump pressure. For all surface and intermediate casing jobs pump a maximum of the theoretical displacement plus half the volume of the shoe track. On production casing displacements pump until the plug bumps.
13. If the plug bumps pressure test the casing to the pressure specified in the Drilling Program (usually 500 psi above bump pressure).
14. Casing pressure tests must not exceed 80% of the burst pressure of the casing or the rating of the wiper plug. Hold pressure for 10 minutes.
15. Release pressure, measure and record backflow. If, on surface and intermediate casing, there is flow back - do not pump any volume of mud back as there is the possibility of pumping mud contaminated cement around the shoe.
16. When cementing surface casing, a top cement job shall always be carried (unless otherwise specified in the program) out to ensure cement is at surface. This should be done with a 1" cement stinger using tail cement with 1-3% CaCl<sub>2</sub>.

## **8.8.4 Liner Cementing Procedures**

### **8.8.4.1 Pre-cementing job checks:**

1. Check on cement lab test results. Utilise a low fluid loss, low viscosity, non-settling slurry.
2. Confirm BHT from logs and compare with programmed BHT, notify DM immediately of any significant difference.
3. Check mixwater required and ensure sufficient supplies are on location. Check quality of mixwater.
4. Determine cement volumes based on caliper logs (caliper volume +10%).
5. Check liner and cementing equipment and materials, i.e. hanger, running tools, cement head, float equipment, safety equipment, cement, additives, preflush chemicals, etc.
6. Centralise liner to achieve 70+% stand-off. One centraliser per joint through production zones is recommended.
7. Confirm maximum safe pump rates for circulating mud, pumping slurry, and displacing in order to achieve maximum cement placement efficiency without fracturing the formation. Ensure that cementer is aware of pump rates and pressures to be used.
8. Cement mix water (the same as was used to do the lab tests) is to be kept in thoroughly clean tanks or pits.
9. Calculate volumes of displacements to liner wiper plug at top of liner and to landing collar.
10. Hold safety meeting.
11. Rig up cementing equipment. Aerate the bulk cement well and ensure bulk systems are functioning properly.
12. Perform Surface Line Friction Test at 6 and 8 BPM and record, i.e. pump through open-ended lines and hose (not through Lo-Torc valve) on to rig floor.
13. Condition hole during circulation, reciprocate pipe very slowly and circulate at slowly increasing rates until maximum safe rate has been achieved. This should be after a minimum of 3 hole volumes have been pumped, or pump pressure and mud rheology have stabilised and measurement of returns indicates near 100% wellbore displacement efficiency. Record pressures at the different rates.
14. Set Liner hanger.

### **8.8.4.2 Cementing:**

1. Flush lines and pressure test with water to 1000 psi above maximum expected pressure.
2. Mix and pump flushes at maximum safe rate, minimising surging effect on the hole.
3. Monitor and record return volumes throughout cementing operation.
4. Mix and pump cement slurry at required density, confirming density with a pressurised balance (if available). Pump at maximum safe rate.
5. Record all mixing and pumping rates, volumes and times accurately.
6. Drop pump down plug.



7. Pump displacement at maximum safe rate. Slow pump rate just prior to the pump down plug reaching the liner, noting the volume and amount of pressure increase when the pump down plug shears the liner wiper plug. Re-calculate or correct remaining displacement volume if necessary.
8. Resume pumping at maximum safe rate if possible.
9. Bump plug. If liner is to be drilled out do not pump more than theoretical displacement + 50% of shoe track volume.
10. Pressure test liner to 60% of liner burst pressure, or hanger pressure rating, whichever is lower. The actual pressure will be specified in the drilling programme.
11. Release pressure, measure returns and check for float valve functioning.
12. Set liner packer if applicable. Release setting tool.
13. Circulate out excess cement slurry, DO NOT reverse if a liner top packer has not been set.
14. When cement samples have set pressure test liner top to pressure specified in programme.

#### **8.8.5 Stage Cementing**

The procedure below applies to the use of a stage cementing collar with a free-fall opening plug that is the preferred method except in deviated wells when continuous cementing is required.

1. Rig up cement lines and flush lines with water and pressure test to 1,000 psi above expected maximum pressure.
2. Carry out circulation test, record rates and pressures. Pump preflush.
3. Drop bottom plug (if applicable). Pre-mix and re-circulate slurry until gradient is within safe tolerance.
4. Mix and pump cement.
5. Drop the 1st stage top plug.
6. Displace at pre-determined maximum loss free rate using the cementing pumps (Rig pumps as backup). Before theoretical bumping of the plug, reduce the rate to  $\frac{1}{4}$  to  $\frac{1}{2}$  of full displacement rate. Record pressures at these rates.
7. Bump plug and record bump pressure. Pump a maximum of the theoretical displacement plus half the volume of the shoe track.
8. Release pressure and check for backflow.
9. If backflow is observed, shut the well in, wait for 30 minutes and check again. If backflow continues, shut in well and WOC.
10. Release free-fall stage cementing collar opening plug and wait (approximately 5 1/2 minutes/1000 m for the plug to seat).
11. Increase pressure to open multi-stage cementing collar as per manufacturer's instructions. If plug fails to open, release pressure and wait for another 5-10 minutes.
12. Establish circulation and circulate minimum of 120% of annular contents. Check for spacer-cement returns from 1st stage and for losses.
13. Switch over to the cement line, pressure test line.
14. Pump preflush

15. Pre-mix and re-circulate slurry until gradient is within safe tolerance
16. Mix and pump cement.
17. Drop the stage cementing collar closing plug.
18. Displace at maximum rate using the cementing pumps. During displacement, monitor the pressure; if it is low, continue displacing with the cementing pumps but monitor the returns closely to ensure there are no losses. Before theoretical bumping of the plug reduce the pump rate to approximately  $\frac{1}{4}$  to  $\frac{1}{2}$  of full displacement rate  
**Note:** Pressure surges must be minimised by breaking circulation carefully, particularly on opening the stage cementing collar, to avoid weakening or shearing closing sleeve shear pins.
19. Bump plug into the multiple stage collar. Hold pressure for 5 minutes. Release pressure and pressure test casing to pressure specified in drilling programme for 10 minutes. Release pressure and check for back-flow. In case of back-flow, close in the well and wait on cement.

#### 8.8.6 Reporting

The DSV, Toolpusher and Cement Contractor Supervisor shall complete a Pre Job Checklist prior to commencing the cement job

The DSV shall complete the Casing and Cementing Report.

## 8.9 SQUEEZE CEMENTATION

Squeeze cementing operations are required as follows:

- To abandon specific reservoirs in a multiple reservoir completed well.
- To seal off all perforations when abandoning a well to prevent crossflow between reservoirs.
- To repair defective casing or liner cement jobs.
- To plug a severe lost circulation zone.
- To repair casing leaks.

### 8.9.1 Methods

Squeeze cementing consists of applying surface pressure to force a cement slurry into the annular space between the casing and the formation, into other areas of the well, or into the formation. The following methods may be used in performing a squeeze cementation:

- **A high pressure squeeze.** This is where the slurry is placed using sufficient pressure to fracture the formation. Whole cement slurry is placed into the formation fractures.
- **A low pressure, or hesitation squeeze.** This is where the cement slurry is placed with hydraulic pressure below the fracture pressure of the formation. For example, in a “spot and squeeze” (also called a “block squeeze”), cement is spotted over the required interval, before hydraulic pressure is applied. Hydraulic pressure is then applied in order to force or squeeze the cement filtrate in the pore space of the formation, or the perforations leaving a filter cake of cement solids coating the formation and filling the perforations. In order to build this filter cake, pumping must stop periodically, or hesitate, to allow time for the filtrate to seep into formation pore space and reduce hydraulic pressure.
- **A circulation squeeze:** This should be used when there is not enough cement behind the casing string, or the cement is shown to be poorly bonded in places where it is required for zonal isolation. The casing is perforated in two places, a packer is set between the perforations and cement is circulated through the annular space between casing and the formation.

### 8.9.2 Guideline

The following squeeze cementation guidelines should be adhered to:

- If an attempt is planned to squeeze cement into perforations or into a casing leak, injection rates must be established before cement is squeezed.
- High squeeze pressures which may induce formation breakdown should be avoided in order to prevent zonal communication via vertical fissures.
- When a packer has been set just above the perforations or zone to be squeezed off, the bottom hole pressure must be kept below 80% of the burst pressure of the weakest casing used. Changing the setting point of the packer or applying back pressure may increase the allowable squeeze pressure. Annular back pressure should be applied in all cases having a differential pressure across the packer greater than 1,500 psi.
- The hesitation squeeze technique should be used in lost circulation zones to aid bridging of the cement solids. This involves squeezing, waiting a few minutes, and squeezing again until no further injection is possible or all cement is used.
- The hesitation squeeze technique is not recommended across perforations, as there is a risk that cement will bridge-off prematurely, and fail to seal the perforations permanently.

- The simplest way to carry out a squeeze is to spot the cement and squeeze it by applying pressure while the annulus is kept closed (bradenhead or poorboy squeeze). Balanced cement plugs are described in Section 8.10.2. A packer must be used if the pressure during the squeeze will exceed the maximum allowable pressure at any point above the planned depth of the cementation.
- If no packer is used, a weighted high viscosity pill of approximately 45 m (150 ft) length should be used as a bottom to retain the cement.
- If there are any perforations below that require to be protected from the squeeze pressure and/or cement that might work its way down the hole, a bridge plug must be set approximately 4.5 m (15 ft) below the interval to be squeezed off.

### **8.9.3 Squeeze Cementing Procedures**

High and low pressure cementation procedures are described below.

#### **8.9.3.1 Spot and Squeeze Cementing Procedure (Low Pressure)**

1. RIH with cementing stinger and spot a weighted high-vis pill.
2. Set a balanced cement plug.
3. Pull back immediately but carefully to approximately three stands (approx. 90 m {300'}) above the theoretical TOC and direct circulate bottoms up.
4. Close the annular BOP.
5. Squeeze away the cement at a constant pressure not exceeding the formation fracture pressure.
6. Squeeze 50% of the available slurry and commence a (hesitation) squeeze.
7. Hesitate and pump in steps of 1 to 10 minutes until the required amount of cement is displaced or injection stops. A minimum 9 m (30') of cement must be left above the zone.
8. POOH with the stinger. Circulate to remove cement from inside pipe.

#### **8.9.3.2 Squeezing Through a Cement Retainer (High Pressure)**

1. Set a drillable cement retainer on drill pipe approximately 9 m (30') above the perforations to be squeezed.
2. RIH with cement stinger on drill pipe and tag retainer. Establish circulation, stab into retainer and perform injection test. Check stinger can be properly stabbed into retainer. Pull out of retainer 1 m (3').
3. Pump the spacer and cement, displace until the spacer reaches the end of the stinger. Back pressure should be applied on the annulus to balance the cement column.
4. Stab into the cement retainer.
5. Squeeze away the cement or until injection stops. Do not hesitate squeeze.
6. Pull out of the cement retainer and pull up 1 stand, reverse circulate clean and POOH.

#### **8.9.3.3 Circulation Squeeze**

1. Perforate the casing at the top and bottom of the repair interval.
2. Set a drillable bridge plug or retainer on drill pipe between the perforations.

3. RIH with cement stinger on drill pipe, stab into the bridge plug and establish circulation.
4. Circulate a solids-free fluid at increasing rates until the pressure at the perforations equals the leak-off pressure.

**Notes:** If circulation cannot be established, the job should not continue. DM shall be consulted who shall advise the next course of action.

5. Pull out of the bridge plug, and pick up 2 m. Pump spacer followed by the cement slurry to a level 10m above the bridge plug.  
Back pressure should be applied on the annulus to balance the cement column.
6. Stab back into the bridge plug and displace cement.
7. Pull out 27m above the top perforations and reverse circulate drill pipe clean. POOH..

## **8.10 PLUG CEMENTATION**

Cement plugs are placed in the wellbore for the following reasons:

- To cure lost circulation while drilling.
- To sidetrack an existing wellbore.
- To abandon a depleted zone.
- To abandon a well.

### **8.10.1 Guidelines**

The following general guidelines shall be adhered to during plug cementation:

- In general cement plugs should not exceed 100 m in length. If the hole is badly washed out, it may be better to set 2 short plugs over the washed out section.
- For open hole plug backs, any caliper information available should be used to calculate the slurry volume (+10% excess). If no caliper is available 20% above theoretical volume should be used.
- The TOC should be calculated to be 15 m above the minimum required top.

### **8.10.2 Setting a Balanced Plug Procedure**

When setting a balanced plug, the following procedure shall be followed:

1. RIH with a tubing stinger, at least the length of the plug, on drill pipe to 60 m (200ft) below the planned depth of the bottom of the plug.
2. Circulate 120% of the cementing string contents before setting the cement plug. The mud must have a constant weight before pumping the cement.
3. Spot a minimum of 60 m of viscous mud pill below plugs setting depth.
4. Pull up to setting depth.
5. Pump the spacer and the cement. The slurry should be batch mixed, When this is not possible the slurry must be re-circulated until a consistent weight is achieved.
6. Pump the required volume of spacer after the cement to balance plug.
7. Under-displace with mud, according to the program, to avoid backflow.
8. Do not rotate string in cement plug.
9. Pull back immediately and slowly to approximately 30 m above TOC and direct circulate bottoms up. Do not reverse circulate above plugs set in open hole.
10. If the plug has to be tagged after the cement has hardened, keep moving the stinger while WOC.
11. Set the next plug or POOH.

## **8.11 CEMENT EVALUATION**

Cement evaluation techniques which may be applied are described below

### **8.11.1 Temperature Survey**

A temperature survey can be used to indicate both the presence of cement and TOC during setting as the chemical reaction gives off heat. The amount of heat depends on well conditions and slurry design. Temperature surveys cannot be used for qualitative evaluation of the cement job because no indication of bonding is given.

For this reason temperature surveys are rarely run.

- The temperature survey can be used to determine TOC where a cement evaluation log (CBL, CBL/VDL, CET etc.) is not planned or may be unreliable due to size of casing.
- Optimum time to run a temperature survey is between 6 – 12 hours after cementation.
- For best results, the fluid inside the casing must be left undisturbed following completion of cementation until the survey is made
- The log should be recorded while running in the hole.

#### **8.11.1.1 Interpretation**

The temperature survey log should follow the formation temperature gradient until a step increase in temperature indicates TOC. Below the TOC the temperature is dependant upon the mass of cement in the annulus. The greater the mass of cement the greater the temperature. Consequently, the log should correlate with the caliper (if run). Lack of correlation is probably an indication of channeling. Temperature anomalies can also be related to poor zonal isolation and resulting fluid movement behind casing.

### **8.11.2 Cement Evaluation Logs**

Electricline (sonic) logs may be run to evaluate casing cementations. These logs require cement to have set and hardened for several days before the logs can give reliable indication of cement bonding and isolation quality. For this reason, such logs are generally not run as part of the drilling operations, and are more commonly carried out as part of a subsequent well completion.

## 8.12 QUALITY CONTROL AND DOCUMENTATION

This Section defines reports prepared during and after cement jobs..

### 8.12.1 Contractor Reports

The Cementing Contractor shall provide a field report to the DS not later than 24 hours following the completion of any cement job. The required contents of this report are tabulated below.

Topic	Required Information
Cement	<ul style="list-style-type: none"> <li>• Class of cement and amount used</li> <li>• Cost of cement</li> </ul>
Additives	<ul style="list-style-type: none"> <li>• Names of additives and amounts used</li> <li>• Cost</li> </ul>
Spacer	<ul style="list-style-type: none"> <li>• Composition</li> <li>• Cost</li> </ul>
Cement Placement	<ul style="list-style-type: none"> <li>• Estimated TOC</li> </ul>
Volume Requirements	<ul style="list-style-type: none"> <li>• Spacers</li> <li>• Slurries</li> <li>• Displacement water</li> </ul>
Operations Information	<ul style="list-style-type: none"> <li>• General (e.g. pipe reciprocation)</li> <li>• Cement wiper plugs</li> <li>• Displacement rate and pump efficiency</li> <li>• Plug bump volume, over-displacement</li> </ul>
Pressure Chart	<ul style="list-style-type: none"> <li>• Description of all operations marked on chart</li> <li>• Start and stop times</li> <li>• Pressure test of casing</li> </ul>
Drilling Fluid Data	<ul style="list-style-type: none"> <li>• Type</li> <li>• Weight</li> <li>• Rheology and gels</li> </ul>
Centralisation	<ul style="list-style-type: none"> <li>• Type, depths and spacing</li> </ul>
Cementer's Comments	<ul style="list-style-type: none"> <li>• General comment on the performance of the cementing procedures and programme together with recommendations for future wells</li> </ul>

**Table 50. Cementing Contractor Reporting Requirements.**

### 8.12.2 GSLM's Reports

The DSV shall compile the reports as listed in the table below.

- Casing and cementing report
- Abandonment report

Secondary and remedial cementation do not require a specific reporting format. Data pertaining to the cement plug or squeeze should be detailed on the Abandonment Cement Plug Report.



## Appendix 1.1: Cementing Calculations - Casing

PRIMARY CEMENTATION CALCULATIONS - CASING	
PROCEDURAL STEP	SUB CALCULATIONS
1. Calculate Tail Slurry Data	<p>1.1 Calculate Volume</p> <ul style="list-style-type: none"> <li>• <i>Total Volume (bbls)</i> = Shoetrack vol + (rathole + excess) + (annulus to top of tail + excess)</li> <li>• <i>Total Volume (cu. ft.)</i> = bbls × 5.615</li> </ul> <p>1.2 Calculate Cement Requirements</p> <ul style="list-style-type: none"> <li>• Sacks of Cement = slurry cu. ft. ÷ slurry yield (cu. ft./sx)</li> <li>• <i>Tonnes of Cement (MT)</i> = <math>\left( \frac{\text{sacks of cement} \times 94}{2200} \right)</math></li> </ul> <p>1.3 Calculate Mixwater Requirements</p> <ul style="list-style-type: none"> <li>• <i>Total Mixwater (bbls)</i> = <math>\left( \frac{\text{sacks of cement} \times \text{mixwater (gal/sx)}}{42} \right) + \text{excess (dependent on job)}</math></li> </ul> <p>1.4 Calculate Additive Requirements (for each additive)</p> <ul style="list-style-type: none"> <li>• <i>Total Volume</i> = Concentration (gal / sk) × sacks of cement (BWOC)</li> <li>• <i>Total Volume</i> = Concentration (% BWOC) × total mix water (BWOC)</li> </ul> <p><u>Note:</u> * Water excess to be considered if additives are mixed with water.</p>
2. Calculate Lead Slurry Data	<p>2.1 Calculate Slurry Volume</p> <ul style="list-style-type: none"> <li>• <i>Total Volume (bbls)</i> = <math>\frac{(\text{hole / csg annulus to TOC or shoe}) + (\text{csg / csg annulus vol to TOC (if require overlap)})}{5.615}</math></li> <li>• <i>Total Volume (cu. ft.)</i> = bbls × 5.615</li> </ul> <p>2.2 Calculate Cement Requirements (As per 1.2)</p> <p>2.3 Calculate Mixwater Requirements (As per 1.3)</p> <p>2.4 Calculate Additive Requirements (As per 1.4)</p>
3. Calculate Displacement Data	<p>3.1 Calculate Displacement Volume</p> <ul style="list-style-type: none"> <li>• <i>Total Volume to Float Collar (bbls)</i></li> <li>• <i>Mud Displacement Volume (bbls)</i></li> <li>• <i>Pump Strokes to Bump Plug</i></li> </ul>
4. Calculate Minimum Hydrostatic During Job	<p>4.1 Assume minimum hydrostatic when (low weight) spacer pre flush in annulus</p> <ul style="list-style-type: none"> <li>• <i>Ht of Spacer / preflush</i> = <math>\frac{\text{volume (bbls)}}{\left( \frac{\text{hole ID}^2 - \text{csg OD}^2}{1029.4} \right)}</math></li> <li>• <i>Loss in psi hydrostatic</i> = (mud wt - spacer wt) × 0.0519 × spacer ht</li> <li>• <i>Hydrostatic Gradient</i> = MW (ppg) - <math>\left( \frac{\text{hyd loss (psi)}}{0.052 \times \text{Depth of Interest (DOI) (ft.)}} \right)</math></li> </ul>

Table 52. Primary Cementing Calculations – Casing (i)

PRIMARY CEMENTATION CALCULATIONS - CASING	
PROCEDURAL STEP	SUB CALCULATIONS
5. Calculate Maximum Hydrostatic	<p>5.1 Calculate Cement Hydrostatic (Tail)  <math>= wt\ cmt\ (ppg) \times tail\ ht \times 0.052</math></p> <p>5.2 Calculate Cement Hydrostatic (Lead)  <math>= wt\ cmt\ (ppg) \times lead\ ht \times 0.052</math></p> <p>5.3 Calculate Spacer Hydrostatic  <ul style="list-style-type: none"> <li>• Calculate spacer ht = <math>\left( \frac{spacer\ vol}{annulus\ volume\ (bbl / ft)} \right)</math></li> <li>• Calculate spacer Hydrostatic = <math>spacer\ wt\ (ppg) \times ht\ (ft) \times 0.052</math></li> </ul> </p> <p>5.4 Calculate Preflush Hydrostatic (as applicable)  <ul style="list-style-type: none"> <li>• Calculate preflush ht = <math>\left( \frac{preflush\ vol}{annulus\ volume\ (bbl / ft)} \right)</math></li> <li>• Calculate Preflush Hydrostatic = <math>preflush\ wt \times ht \times 0.052</math></li> </ul> </p> <p>5.5 Calculate Mud Hydrostatic (as applicable)  <ul style="list-style-type: none"> <li>• Calculate Mud ht = <i>top of preflush to surface (ft)</i></li> <li>• Calculate Mud Hydrostatic = <math>MW \times ht \times 0.052</math></li> </ul> </p> <p>5.6 Calculate Total EMW =  <math>Total\ of\ (5.1 - 5.5) \div 0.052 \div Depth\ (ft)</math></p> <p><u>Note:</u>            * Calculate hydrostatic at known weak points in the wellbore and advise DTL if fracture gradient will be exceeded.</p>
6. Calculate Job Time	<p>6.1 Calculate Mixing/Pumping Time  <ul style="list-style-type: none"> <li>• Total Time = <math>(slurry\ bbls \div pumping\ rate) + 10\ minute\ pre\ mix\ time\ (or\ as\ advise)</math></li> </ul> </p> <p>6.2 Calculate Post Cement Spacer/Post Flush Time  <ul style="list-style-type: none"> <li>• Total Time = <math>bbls \div pumping\ rate\ (bpm)</math></li> </ul> </p> <p>6.3 Calculate Displacement Time  <ul style="list-style-type: none"> <li>• Total Time = <math>displacement\ volume\ (bbls) \div displacement\ rate\ (bpm)</math></li> </ul> </p> <p>6.4 Calculate Total Job Time  <math>Total\ of\ (6.1 - 6.4) \times 2\ (100\% SF)</math></p> <p>* Compare to thickening time and advise DTL if thickening time is insufficient.</p>

Table 52 (cont'd). Primary Cementing Calculations – Casing (ii)

## Appendix 1.2: Cementing Calculations - Liner

PRIMARY CEMENTATION CALCULATIONS - LINER	
PROCEDURAL STEP	SUB CALCULATIONS
1. Calculate Hydrostatic Loss/Increase Due To Pre-Flush	<p>Assume worst case with pre-flush in annulus.</p> <p>1.1 Calculate preflush ht <math>ht (ft) = \frac{vol\ preflush\ (bbls)}{\left(\frac{hole\ ID^2 - liner\ OI^2}{1029}\right)}</math></p> <p>1.2 Calculate Hydrostatic loss/gain <math>loss/gain\ (psi) = (MW - PF\ wt) \times 0.052 \times ht\ preflush</math></p> <p>+ check against pore pressure for safety margin.</p>
2. Calculate Slurry Volume For Job	<p>2.1 Calculate shoetrack volume <math>= shoetracklength \times \left(\frac{ID\ liner^2}{1029.4}\right)</math></p> <p>2.2 Calculate rathole Volume <math>= rathole\ length \times \left(\frac{OI^2}{1029.4}\right)</math></p> <p>2.3 Calculate O.H./Liner Annulus <math>= (Liner\ Shoe\ Depth - Casing\ Shoe\ Depth) \times \left(\frac{OI^2 - liner\ OI^2}{1029.4}\right)</math></p> <p>2.4 Calculate Liner/Casing Annulus <math>= (Casing\ Shoe - Line\ Hanger\ Depth) \times \left(\frac{ID\ casing^2 - liner\ OI^2}{1029.4}\right)</math></p> <p>2.5 Calculate Casing Vol to planned TOC <math>= (Hanger\ Depth - TOC) \times \left(\frac{ID\ casing^2 - liner\ OI^2}{1029.4}\right)</math></p> <p>2.6 Apply Excess to 2.2 and 2.3.</p> <p>2.7 Sum 2.1, 2.2, 2.3, 2.4, 2.5 and 2.6 for total volume slurry (bbls)</p> <p>2.8 Calculate Slurry Vol (cu. ft.) <math>= Total\ Vol\ (bbls) \times 5.615</math></p>
3. Calculate Cement Mixwater and Additive Volumes	<p>3.1 Calculate cement volume required <math>= \left(\frac{Slurry\ Vol\ (cu.\ ft.)}{yield\ (cu.\ ft./sk)}\right)</math></p> <p>3.2 Calculate cement requirement (MT) <math>= \left(\frac{No.\ sacks \times 94}{2200}\right)</math></p> <p>3.3 Calculate Mixwater Volume (bbls) <math>= \left(\frac{Mixwater\ gal / sk \times No.\ sacks}{42}\right) + excess</math></p> <p>3.4 Calculate Additive Requirements (for each) <math>= additive\ concentration\ (gal / sk) \times No.\ sacks\ cement</math></p> <p><u>Note:</u> * Excess water to be considered in additives requirement.</p>
4. Calculate Cement Line Volume	<p>4.1 Calculate Cement Line Volume <math>= length\ (ft) \times \left(\frac{ID\ liner^2}{1029.4}\right)</math></p>
5. Calculate Displacement Volume to Land Dart in Wiper Plug	<p>5.1 Calculate Volume to Land Dart = Total Displacement Volume <math>= length\ to\ wiper\ plug\ seat \times \left(\frac{ID\ running\ string^2}{1029.4}\right)</math></p> <p>5.2 Calculate Mud Displacement Volume <math>= total\ disp\ vol - spacer\ behind\ volume</math></p> <p>5.3 Calculate Strokes to Shear Wiper Plug <math>= \left(\frac{Result\ of\ 5.2}{Pump\ output\ (bbl / sk)}\right)</math></p>

Table 53. Primary Cementing Calculations – Liner (i)

PRIMARY CEMENTATION CALCULATIONS - LINER	
PROCEDURAL STEP	SUB CALCULATIONS
6. Calculate Total Displacement Volume	<p>6.1 Calculate Displacement Volume from Wiper Plug-Landing Collar = {wiper plug seat - landing collar} <math>\times \left( \frac{40 \text{ in}^2}{1029.4} \right)</math></p> <p>6.2 Calculate Total Displacement Volume = 'Result 5.2' + 'Result 6.1'</p> <p>6.3 Calculate Strokes to bump = <math>\left( \frac{\text{'Result 6.2'}}{\text{pump output (bbl / stk)}} \right)</math></p>
7. Calculate Differential Pressure & Hydrostatic @ End of Job	<p>7.1 Calculate Differential Pressure prior to bump</p> <p>7.1.1 Calculate cmt hyd (psi) = <math>\text{cmt wt} \times 0.052 \times \text{cmt ht}</math></p> <p>7.1.2 Calculate spacer hyd (psi) = <math>\text{spacer wt} \times 0.052 \times \text{spacer ht}</math></p> <p>7.1.3 Calculate mud hyd (psi) = <math>MW \times 0.052 \times (\text{depth liner} - \text{cmt ht} - \text{spacer ht})</math></p> <p>7.1.4 Calculate cmt hyd in liner = <math>\text{shoetrack length} \times 0.052 \times \text{cmt wt}</math></p> <p>7.1.5 Calculate spacer behind in liner = <math>\text{spacer ht} \times 0.052 \times \text{spacer wt}</math></p> <p>7.1.6 Calculate mud hyd in string = <math>MW \times 0.052 \times (\text{shoe depth} - \text{cmt ht} - \text{spacer ht})</math></p> <p>7.1.7 Calculate differential pressure = <math>(7.1.1 + 7.1.2 + 7.1.3) - (7.1.4 + 7.1.5 + 7.1.6)</math></p> <p>7.1.8 Calculate hydrostatic (ppg) at end job</p> $\text{ppg} = \left( \frac{\sum (7.1.1 + 7.1.2 + 7.1.3)}{0.052 \times \text{shoe depth}} \right)$ <p><u>Note</u></p> <ul style="list-style-type: none"> <li>* Check final hydrostatic against minimum fracture gradient in open hole.</li> <li>* If hydraulics programme is available calculate ECD prior to end displacement.</li> </ul>
8. Calculate Running String wt.	<p>8.1 Calculate Running String wt in mud = <math>\text{string ppf} \times \text{length} \times \text{buoyancy factor of mud}</math></p> <p>8.2 Running wt in cement = <math>\text{string ppf} \times \text{length in cmt} \times \text{buoyancy factor of cement}</math></p> <p><u>Note</u></p> <ul style="list-style-type: none"> <li>* Check running string wt on POOH to TOC and when out of cement.</li> </ul>

Table 53 (cont'd). Primary Cementing Calculations – Liner (ii)

### Appendix 1.3: Cementing Calculations – Balanced Plug

PRIMARY CEMENTATION CALCULATIONS - BALANCED PLUG	
PROCEDURAL STEP	SUB CALCULATIONS
1. Calculate Slurry Volume	<p>1.1 Calculate Slurry Volume (bbls) <math>= \text{required ht} \times \left( \frac{ID \text{ csg}^2 \text{ or } OH^2}{1029.4} \right)</math></p> <p>1.1.1 If across shoe or stub, calculate</p> <ul style="list-style-type: none"> <li>a) ht cmt in cased hole section</li> <li>b) volume cmt in in cased hole section</li> <li>c) ht cmt in open hole section</li> <li>d) volume cmt in open hole section</li> <li>e) total volume = sum 'b' + 'd'</li> </ul> <p>1.2 Calculate Slurry Volume (cu. ft.) = Total vol (bbls) x 5.615</p>
2. Calculate Cement and Additive Requirements	<p>2.1 Calculate sacks cement required (no. of sacks) <math>= \left( \frac{\text{slurry vol (cu.ft.)}}{\text{slurry yield (cu. ft./sk)}} \right)</math></p> <p>2.2 Calculate cement required (MT) <math>= \left( \frac{\text{no. of sacks} \times 94}{2200} \right)</math></p> <p>2.3 Calculate mixwater volume <math>\text{gals} = \text{no. of sacks cmt} \times \text{mixwater (gal / sk)} + \text{excess}</math>  <math>\text{bbls} = \left( \frac{\text{gals mixwater}}{42} \right)</math></p> <p>2.4 Calculate additive requirements (for each) <math>= \text{no. of sacks cmt} \times \text{additive concentration (gal / sk)}</math></p> <p><u>Note:</u>          * Excess water to be considered in additive requirement.</p>
3. Calculate Minimum Hydrostatic	<p>3.1 Calculate ht of spacer or preflush (worst case w/ preflush spacer out of pipe)</p> $ht = \frac{\text{vol spacer or preflush}}{\left( \frac{\text{hole or csg ID}^2 - \text{pipe OD}^2}{1029.4} \right)}$ <p>3.2 Calculate hydrostatic loss/gain</p> $\text{psi} = (\text{MW (ppg)} - \text{spacer / preflush wt (ppg)}) \times 0.052 \times \text{spacer ht preflush}$ <p><u>Note:</u>          * Check resultant EMW against any exposed formation pore pressures at depth of interest.</p>

Table 54. Primary Cemnting Calculations – Balanced plug (i)

PRIMARY CEMENTATION CALCULATIONS - BALANCED PLUG	
PROCEDURAL STEP	SUB CALCULATIONS
4. Calculate Spacer Volume Behind Cement	<p>4.1 Calculate volume behind (bbls) <math>= ht \text{ spacer or preflush} \times \left( \frac{pipe \text{ ID}^2}{1029.4} \right)</math></p>
5. Calculate Displacement Volume to Balance	<p>5.1 Calculate cmt ht prior to pull back <math>ht \text{ ft} = \left( \frac{slurry \text{ volume (bbls)}}{annulus \text{ vol (bbl / ft)} + DP \text{ string capacity (bbl / ft)}} \right)</math></p> <p><u>Note:</u> If stinger used calculate slurry vol inside and outside stinger. Subtract this total volume stinger from total cmt volume and use remainder in formula above to gain ht outside DP. Then add stringer length to get total ht.</p> <p>5.2 Calculate ht spacer prior to pullback <math>ht \text{ spacer (ft)} = \left( \frac{spacer \text{ volume}}{annulus \text{ vol (bbl / ft)} + DP \text{ capacity (bbl / ft)}} \right)</math></p> <p>5.3 calculate ht of mud to displace <math>= cement \text{ string length} - slurry \text{ ht (5.1)} - spacer \text{ ht (5.2)}</math></p> <p>5.4 Calculate displacement volume (bbls) <math>= \left( \frac{DP \text{ ID}^2}{1029.4} \right) \times ht \text{ of mud required (5.3)}</math></p> <p>5.5 Calculate displacement volume (STKS) <math>= \frac{(disp \text{ vol (bbls)} - 2 \text{ bbls under displacement})}{pump \text{ output (bbl / stk)}}</math></p>

Table 54 (cont'd). Primary Cementing Calculations – Balanced Plug (ii)

## **CHAPTER 9 EVALUATION**

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## 9.1 OBJECTIVES

The primary objectives of evaluation are:

- To obtain the maximum amount of subsurface information as detailed in the Drilling Program, in a safe and cost-efficient manner.
- To ensure that data acquisition is not impaired or damaged by drilling fluids or drilling practices during the drilling of the wellbore.
- To ensure that the DSV retains overall control and responsibility for the safe and efficient execution of all evaluation activities performed at the wellsite.

It is important that the geological objectives and requirements are fully understood and documented in the Drilling Program.



## 9.2 RESPONSIBILITIES

At the well site, the Wellsite Geologist (WGL) is responsible for the supervision of the evaluation of the well. The DSV controls operations on the rig and executes the evaluation program as requested by the WGL. The DSV is also responsible for the following activities:

1. Ensuring that equipment and logging personnel are on the site and prepared for activities.
2. Ensuring that all personnel involved in evaluation are trained and qualified for the job.
3. Ensuring that logging and testing tools are run in accordance with the Drilling Program.
4. Managing safety, in particular for well control, explosives, chemical cutters and radioactive tools.
5. Reporting of logging and testing activities, in conjunction with the Wellsite Geologist.

Geological requirements for logging shall be detailed in the Drilling Program and may be revised during operations. The sequence of logging shall also be included and shall not be changed without an authorised revision to the program.

The responsibilities for the different evaluation activities (electric logging, coring, mud logging, and testing) are defined in the tables below.

### 9.2.1 Generic Responsibilities for all Evaluation Activities

Task	Performed by	Verified by
Specify evaluation requirements	WGL	DM
Mobilise equipment and tools	DSV / DM	DSV / WGL
Run evaluation tools	Contractor	WGL/DSV
Fish for tools (if required)	Contractor	DSV
Revise evaluation program	WGL	DSV/DM
Prepare reports and logs	Contractor/WGL/DSV	DM

**Table 55. Responsibilities for Evaluation Activities - Generic**

### 9.2.2 Specific Evaluation Responsibilities

Task	Performed by	Verified by
<b>Logging</b>		
Authorise commencement and continuation of logging	DSV / WGL	DM
Rig up, monitor hole	Drilling Contractor	DSV
QC wireline logs	WGL	DM
Provide logging results	Logging Contractor	WGL
<b>Coring</b>		
Determine core point	WGL	DM
Approve pulling out to core	DSV	DM
Make up core barrel, cut core, record parameters and recover core	Coring Contractor / Drilling Contractor	DSV
Prepare core description	WGL	DM
Package and ship core	Mud loggers / WGL	DM
<b>Mudlogging</b>		
Prepare unit for start-up, ensure unit safety, calibrate equipment	Mud Logging Contractor	WGL / DSV
Perform mudlogging	Mud Logging Contractor	WGL / DSV
QC mudlog	WGL	DM
Prepare and package cutting samples for transport	Mud Logging Contractor	WGL
<b>Testing</b>		
Identify need for test	WGL	DM
Select test interval	WGL	WGL / DSV / DM
Operate surface test equipment (i.e. separator)	Separator Contractor / Testing Company	DSV
Ensure safety and integrity during the test	Drilling Contractor / Testing Company	DSV
Prepare work instructions	Drilling Contractor / DSV	DM
Monitor operations	WGL / DSV	DM
Monitor recovery, collect samples	WGL	DSV
Conduct the test	Testing Contractor	DSV

**Table 56. Responsibilities for Evaluation Activities - Specific**

### **9.3.0 ELECTRIC LOGGING**

This section describes the electric wireline logging for formation evaluation supervised by the Drilling Department and carried out by contractors.

#### **9.3.1 Responsibilities**

At the wellsite the Wellsite Geologist (WGL) is responsible for the supervision of logging operations, ensuring logs are run in accordance with the logging order form and the quality control of the logs. However, the DSV is responsible for the following activities:

- Ensuring that equipment and logging personnel are on site and prepared for activities.
- Ensuring that fishing equipment for each programmed logging tool is available on location or at a proximal logistics base.
- Controlling operations on the rig.
- Managing safety, in particular for well control, explosives, chemical cutters and radioactive tools.
- Reporting logging activities, in conjunction with the WGL.

#### **9.3.2 Wireline Logging Safety**

Full safety awareness is required at all times and safety meetings should be held prior to all logging operations. The following guidelines must be adhered to:

- All wireline logging personnel must be trained, certified (where applicable) and competent in the job they are doing.
- All wireline contractor personnel must be familiar with the mandatory requirements for explosive and radioactive materials.
- Explosive magazines and radioactive stores must be set aside in a designated, marked area away from the camp and rig traffic.
- The senior representative of the Logging Contractor must ensure that all crew are familiar with and comply with both GSLM and the logging Contractor's safety procedures.
- The Drilling Contractor must ensure that personnel are aware of the dangers of radioactivity and explosives.
- All persons not directly involved in the tasks must be kept well away from sheaves, cable and the winch drum when tools are being run, and when logging tools are at surface.
- Loads must not be moved across the cable when logging operations are in progress.
- The hole must be covered at all times, unless a tool is being run in the hole. A slotted hole cover must be installed whilst running logs.

#### **9.3.3 Wireline Logging Preparation**

The DSV shall ensure the following requirements are met before the start of logging operations.

- The logging unit is in position and ready to rig up at start of operation and the work area, i.e. catwalk, rig floor, etc. is clear of tools which may hinder the operations.
- The Logging Contractor is given assistance from the drilling crew during rigging-up and rigging-down.
- When rigging up, the Logging Contractor shall ensure that the winch operator has the clearest possible view of the rig floor.
- Prior to rigging up, all wireline sheaves shall be adequately guarded. No rig-up or operation is permitted without properly guarded sheaves. All wireline logging tools should also be checked and tested prior to rigging up.

- Logging operations shall only commence when hole conditions are stable. A check trip may be required before any logging run if there were hole problems during the previous run.
- The drilling fluid parameters (in and out) must meet the agreed specification contained in the Drilling Program. The overbalance shall be at least 50 psi for oil wells and 150 psi for gas wells.
- The well condition shall be closely monitored throughout the operation by the Mud Loggers and Drilling Contractor with regard to possible well flow, losses, etc. The well must be circulated through the trip tank during logging operations.
- Fishing equipment must be at the wellsite or available from a proximal supply base for all logging tools. The lengths OD's and connections of all the tools must be recorded.

### 9.3.4 General Logging Operations

The table below provides guidelines which shall be observed during logging operations.

Operation	Guideline
Trip Tank	<ul style="list-style-type: none"> <li>• The hole shall be circulated using the trip tank during logging operations.</li> <li>• The hole must be kept full throughout, and the trip tank volume recorded every 15 minutes.</li> <li>• The trend must be monitored whilst running in and pulling out.</li> </ul>
Calibration	<ul style="list-style-type: none"> <li>• The wireline logging depths must be set to zero at surface and checked when pulling out to surface.</li> <li>• Additional checks must be made at casing depths and at TD.</li> </ul>
Tool Failure	<ul style="list-style-type: none"> <li>• If a tool hangs up while running in, and the section has not been logged before, log whilst POOH.</li> <li>• If one of the detectors on a combination tool does not function properly, log with the remaining detectors which have not been recorded before.</li> <li>• Inform the DM of any tool failure.</li> <li>• If poor hole conditions are anticipated, always log in, as well as out of the hole to secure data.</li> </ul>
Repeat Sections	<ul style="list-style-type: none"> <li>• A 60 m repeat section must be made on each logging run, and a 30 m overlap with previous logging runs must be made.</li> <li>• When running a caliper tool in a section where the top of the logged interval is below the casing shoe a 30 m section over the shoe must be run to check shoe depth and caliper gauge.</li> </ul>
Mud Sampling	<ul style="list-style-type: none"> <li>• Mud shall be sampled from both the pits and flowline just before the end of circulation before a logging job for analysis and resistivity measurement. This must be repeated after check trips if resistivity tools are to be run.</li> </ul>
Wiper Trips	<ul style="list-style-type: none"> <li>• May be required to ensure that the hole and mud conditions remain stable.</li> </ul>
Tension Limits	<ul style="list-style-type: none"> <li>• The weak-point tension limit and cable tension limit must be checked and tool weight in mud calculated before entering open hole.</li> <li>• Normal logging tension should be checked every 300 m in open hole. This is especially important in deviated holes where significant drag can occur.</li> </ul>

**Table 57. Guidelines to General Logging Operations**

#### 9.3.4.1 Log Quality Control

Quality Control of electric logs is the responsibility of the Wellsite Geologist. The following checks shall be conducted:

- a) The depth correlation of all the curves on the log must be checked with each other. The repeat section must be checked with the main log for agreement. The curves must be examined to see if they have sensible values.
- b) The correct logging speed must be verified with the logging engineer. The

acceptable range is  $\pm 10\%$ .

- c) A 60 m repeat section of logs must be made on each run and a 30m minimum overlap with previous runs must be made between successive logging runs. Depth discrepancies must be less than 0.6 m.
- d) Plot both the formation pressure and mud pressures on the formation pressure test plots as they are taken. Inconsistencies in the mud gradient must be checked immediately (a smooth mud gradient should be regarded as a quality check).

### 9.3.5 Tough Logging Conditions

Tough Logging Conditions (TLC) may exist in deviated wells. Logging tools may require installation and running on tubing or drill pipe to ensure all programmed logging can be achieved. The following sections describe the planning and operational guidelines for TLC.

#### Planning and preparation

The following information is required for the Logging Contractor to prepare for a TLC operation:

- Casing depth, size, and weight.
- Liner top (if applicable).
- Hole size and TD.
- Directional data.
- Mud weight and temperature, mud type, relevant mud additives (i.e. LCM ).
- Drill pipe size, grade, tool connections, IDs.
- Drill collars and heavy weight pipe.
- Drill pipe connections, including drill pipe size and weight.
- Details of tubular handling equipment.

#### Running in Hole

The following considerations shall be adhered to:

- The running in speed should not exceed that used when running a packer on drill pipe. Obstructions downhole (e.g. liner tops) should be passed with caution. Break circulation at regular intervals (i.e. every 15 stands).
- A down log should be taken while running in. The Logging Contractor procedures may recommend that the tools do not tag the bottom of the hole but stay a minimum 6 m above. Depth control should be monitored with the drill pipe which should be checked during in-run and out-run.
- Continuous communication is essential between the Driller and the wireline logging unit to ensure that the pulling speed and cable spooling speed are matched, and to minimise reaction time if the tool begins to stick. Downward movement must be minimised when setting slips, as the calliper is in the open position.
- The cable must not be slacked off, to avoid the risk of damaging it at the Side Entry Sub.
- A cable head tension/compression meter readout should be made available to the Driller on the rig floor.
- The side entry sub should not be run in open hole if possible..

### 9.3.6 Attempts to Free Stuck Logging Tools

In preparation to free a stuck logging tool, the weak-point tension, cable tension limit and tool weight in mud must be checked and the Logging Contractor's stretch chart must be available to verify the pull.

**Note:** In the event a logging tool with a radioactive source becomes stuck the DM shall be immediately informed and supplied with all the relevant data. The course of action to be taken shall be formulated by the DSV/DM in consultation with the Logging Contractor. Written approval shall be required from DM prior to execution of the plan.

The table below provides guidelines in how to attempt to free a stuck logging tool (refer also to Chapter 12 of this Manual).

Stuck Position	Guideline
Stuck on Bottom	If the tool is stuck on bottom, close the tool and pull to maximum safe tension to keep the weak-point intact.
Stuck during Logging Upward	If the tool is stuck during logging upward, close the tool and try to go down.
	Free to Descend: <ul style="list-style-type: none"> <li>• Make several attempts to pass the bridge</li> </ul>
	Not Free to Descend: <ul style="list-style-type: none"> <li>• Pull to maximum safe tension to keep weak-point intact</li> </ul>

**Table 58. Guidelines whilst Attempting to Free Stuck Logging Tools**

If a tension meter is installed on top of the tool and does not register any overpull, then the cable is stuck.

- Make a stuck point estimation by stretch measurement.
- Pull up to cable tension limit slowly, checking for any response on the cable head tension meter.
- If the tool does not come free immediately, additional attempts to work the tool should be considered in consultation with the Logging Contractor. Once the tool is stuck, pulling on the cable does not help.

If the tool fails to come free after several attempts have been made, stripping over is the next course of action. This technique makes use of the cable as a guide for the overshot.

On no account shall an attempt be made to break the weak point unless permission has been given by the DM.

**Before stripping operations, a meeting shall be held at the wellsite with all relevant personnel to review the operating procedure.**

### 9.3.7 Stripping Over

If the tool fails to come free after several attempts have been made, stripping over should be the next course of action. This technique makes use of the cable as a guide for the overshot. **On no account shall an attempt be made to break the weak point** unless permission has been given by the DM.

The following procedure shall be used:

1. Hold a pre-job safety meeting to discuss the task. This shall involve as a minimum the WSG, DSV, toolpusher, logging contractor and mud engineer.

2. Apply tension to the cable as advised by the Logging Contractor.
3. Insert T Bar, clamp and hang on rotary table.
4. Cut cable above rotary table. Connect a spear head to the hole end of the cable, and a spear head overshot assembly to the unit end.
5. Make up wireline overshot to drillpipe.
6. Install a circulating sub in the fishing assembly one stand above the overshot.
7. Thread the cable with the overshot through the drill pipe, stand by stand, maintaining the tension in the cable.

**Note:** While running in with the overshot a decrease in cable tension may occur indicating that the tool has come free. In this case pull the tool up until the overshot latches onto the fishing head. The procedure is then as before.

8. Prior to latching on the fish install the special bushing and land the cable in it. Circulate to remove debris in the overshot and on top of the tool before latching on the fish, and record pressure versus pump strokes.
9. After circulating, connect spear head overshot to spear head and apply tension to the cable as advised by the Logging Contractor.

**Note:** If a radioactive tool is stuck, circulate bottoms up and have the Logging Contractor monitor the mud returns with a GR tool placed in the return line. No personnel other than the Logging Contractor's personnel shall be allowed near the mud pits or the return lines.

10. Lower the drill string and latch onto the fish. Do not locate or engage the logging tool with more than the weight advised by the Logging Contractor. A pressure increase may indicate if the fish is caught in the overshot. A cable head tension increase when lowering the drill string, or a decrease when pulling the drill string, indicates that the fish is connected.
11. After latching onto the fish, part the cable at the weak point with the travelling block, remove the spearhead overshot combination, connect the cable together and wind in.
12. Ensure that with the tool engaged in the overshot, circulation remains possible, using the circulating sub if necessary.
13. Pull the string and recover the fish. Do not rotate the string while pulling out.

**Note:** If a tool with a radioactive source is stuck, the weak link must not be broken without approval by the DM. Reverse strip out the hole.

When handling a retrieved source, the following procedure shall be adhered to:

- a) Limit rig personnel to the minimum required on the rig floor.
- b) Pull the source as far as possible in the derrick (minimum 15 m {50 ft}).
- c) Cover the rotary table, close the rams, then all rig personnel except Driller must leave the rig floor.

The Driller shall assist the Logging Contractor to lay down the equipment.

## 9.4.0 CORING

This section describes the coring operations for formation evaluation supervised by the Drilling Department and carried out by contractors.

### 9.4.1 Responsibilities

All coring requirements shall be detailed in the Drilling Program.

The WGL/DSV shall verify that sufficient Fibreglass/Aluminium barrels and endcaps are on site and that a cut-off saw for core cutting is available. If the core is to be seal peeled the WGL shall ensure that the core bath is working and that sufficient supplies of seal peal are available.

The WGL shall be responsible for determining when the core point has been reached. Upon reaching the core point, the DSV shall be informed. The DSV shall instruct the Drilling Contractor to stop drilling and to prepare for cutting the core. The WGL shall confirm that the program specifications for determining the core point have been met.

The WGL shall be responsible for geological descriptions of the core and any wellsite testing to be carried out. The DSV shall ensure that the core is recovered safely and in such a way as to minimise damage to the core.

### 9.4.2 Coring Procedures

#### Preparation

The following preparations shall be made prior to cutting core:

- Hole conditions must be suitable for cutting core. Particularly, the drilling fluids shall be conditioned to the programmed properties before pulling out of the hole.
- The last BHA pulled before coring shall be carefully checked for gauge. If the bit is more than 1/16" under gauge, consideration should be given to reaming the hole with a full gauge bit. Reaming BHA should have similar stabiliser placement as coring BHA.
- The bit and BHA must be carefully checked for broken and lost cutters after pulling out the hole. Where a severe loss of cutters has occurred, **a junk run shall be made**. The hole must be circulated after running to bottom before commencing to cut core.

#### 9.4.2.1 Conventional Coring

The following generic procedures should be used to assist in compiling the detailed procedures:

1. Run in the hole slowly, beware of hanging up in open hole.
2. If reaming is necessary, pump at maximum allowable rate (determined by the core barrel specification and normal drilling engineering considerations). Do not exceed 30 RPM and maintain minimal WOB. After reaming a section pull back to check trip the reamed section.
3. Tag the bottom gently with high circulating rate without rotation until the mud weights in and out are the same.



4. Drop the ball and when it seats measure slow circulating rates (SCRs). Start rotating and record the pressures on and off bottom. If back flow is present before dropping the ball pump a heavy slug. Prior to the ball seating slow the pump.

**Note:** As a rule of thumb, the ball should take 3 minutes per 1,000 ft to drop.

5. The starting WOB must be applied slowly, and additional weight and RPM applied smoothly until the coring rate is maximised. Watch carefully for any indication of torque increase, ROP decrease or pump pressure change. The Driller shall inform the DSV of any change immediately. Changes may indicate the following:
  - a) A pressure increase when coring may be due to plugging of the barrel, "O" ringing or plugging of the waterways of the corehead, or a change in formation.
  - b) If the ROP is simultaneously reduced, the corehead is probably ringed or plugged. Continuation in this condition shall seriously damage the corehead.
  - c) A decrease in pump pressure and ROP, accompanied by erratic torque readings, indicates jamming of the core. The barrel must be pulled out of the hole.

**Note:** Barrel plugging can be checked by comparing the off-bottom pressure with that recorded prior to coring. If plugging is suspected the barrel must be pulled out of the hole.

When making a connection or pulling off bottom, overpull may be seen as the core catcher grips the core. Pull to a maximum of 2,200 lbs. overpull, after allowing for drag. If the core fails to break, start circulating up to the maximum used while coring and hold the overpull until the core breaks.

6. Cut core until the barrel is full or becomes jammed, the end of the programd coring interval is reached, or cuttings indicate that the required section is cored.
7. Circulate bottoms up, condition the mud and POOH.

**Note:** Extreme care must be taken when tripping with a core barrel. Flow checks must be performed as normal when tripping out of hole, and any deviation from expected hole fill-up volume must be investigated. When pulling out with a core, do not rotate and attempt at all times to minimise jarring or shock loads. The slips must be set carefully. POOH slowly and watch the well closely as the corebarrel is a tight fit in the hole and acts as a piston. Swabbing the well can easily occur.

#### 9.4.2.2 Oriented Coring

Oriented coring provides the data to determine the amount of dip and direction of tilt of the formations cored. Scribe knives mark the core and electronic multishot survey instruments measure and record the orientation of the scribe marks. Due to magnetic interference, orientated coring must not be done less than 18 m (60 ft) below the shoe. Additional checks must be made as follows:

- Identify that the main knife and centre punch is installed in accordance with manufacturer's drawings.
- Check that the electronic multishot survey instruments have sufficient battery life and memory for the duration of the coring and surveying.

Two NMDCs shall be run above the coring equipment to reduce magnetic interference from the drill string.

#### 9.4.2.3 Coring Unconsolidated Formations

- a) In unconsolidated formations, face discharge coreheads, fibreglass inner barrels, extended pilot shoes and special core catchers shall be used.
- b) Circulating rates shall be the minimum required to keep the hole clean and sufficiently cool the corehead.

#### 9.4.2.4 Rat-hole Coring

Coring a hole diameter smaller than the existing hole diameter is called rat-hole coring. When rat-hole coring, place existing hole sized stabilisers (i.e., 8 1/2" stabiliser if the existing hole size is 8 1/2") above the core barrel. On subsequent cores place these stabilisers correspondingly higher in the string, and place rat-hole sized drill collars and stabilisers above the core barrel.

No more than 36 m (120 ft) of rat-hole core should be cut without opening the hole.

### 9.4.3 Coring Assemblies

The coring assembly shall be considered on a well by well basis.

#### 9.4.3.1 Coring Bits

A range of coring bits shall be provided by the Coring Contractor. The bit to be run shall be determined by the last bit run performance and grading. Face discharge coreheads shall be used in unconsolidated formations.

#### 9.4.3.2 Core Barrels

The guidelines below must be checked by the Coring Contractor and verified by the DSV:

- Make up torque is in accordance with manufacturer's figures.
- Bearing assembly free.
- Inner barrel straight, with minimal corrosion on steel barrels.
- Inner barrel space-out is correct in accordance with manufacturer's figures.
- Barrel stabilisers are the correct gauge.
- Safety joint clean and properly lubricated.
- Ball seat is compatible with the ball.
- Fibreglass/Aluminium inner barrels made up to manufacturers specifications.
- Clamps and lifting equipment available.

#### 9.4.3.3 Drill String

The following steps in planning the drillstring configuration shall be made when preparing to core:

- Drill collar weight must be calculated to allow the maximum planned WOB plus 20% extra.
- Drill pipe must be drifted when pulling out the hole for coring to ensure that the ball will pass through. New pipe added whilst coring must also be drifted.
- Full gauge stabilisers may be run at 9 m and 27 m above the top core barrel stabiliser.
- Jars should **always** be run in the coring / drilling assemblies.

#### 9.4.4 Coring Fluids

Any special requirements for coring fluids shall be included in the Drilling Program.  
The general requirements for coring fluids are:

- The mud gradient should not exert an overbalance over the formation pressure of more than 200 psi.
- The static fluid loss should be less than 8 ml/30 min.
- The viscosity and yield point should be as low as possible to reduce core erosion.
- The solids content should be as low as possible to prevent core contamination.
- The mud filtrate salinity and composition should be as close as possible to that of the formation water.
- Water-based mud should be properly deoxygenated with an oxygen scavenger.
- No surfactants shall be used in the mud.

The mud shall be conditioned by the Drilling Fluids Engineer before pulling out for coring.

Any mud losses should be controlled before starting coring. LCM must not be pumped through a core barrel unless necessary.

#### 9.4.5 Core Recovery and Packing

- A pre-job safety meeting must be held before pulling the core barrel through the rotary table to ensure that all personnel understand the job and potential hazards (e.g. trapped pressures and catcher failure, dropping core onto hand/feet).
- If there is any possibility of the core containing H<sub>2</sub>S, only the DSV, Driller, Coring Contractor, WGL and the minimum necessary number of crew shall be present when pulling the core barrel through the rotary table. If H<sub>2</sub>S is suspected, all personnel must wear breathing apparatus until it is confirmed that H<sub>2</sub>S is absent.
- The inner core barrel shall be retrieved/laid down only in single sections (10m).
- Every precaution shall be taken to ensure that inner barrel is protected during retrieval to avoid damaging the core.

##### 9.4.5.1 Barrel Inspection on Core Recovery

- Ensure that the core barrel connections do not come apart when recovering the core or handling the barrels.
- When raising the inner barrel from the outer barrel, a water hose shall be used to flush drilling fluid from the barrel. Visually examine each inner barrel connection to ensure that it is firmly shouldered.
- If connection is not tight or appears suspect, the inner barrel clamp shall be installed and the connection tightened before continuing to recover the inner barrel.
- When core barrels are laid down, all connections shall be cleaned and doped and proper thread protectors shall be installed on all connections.

##### 9.4.5.2 Core Handling

Any special requirements for packing shall be given in the **Drilling Program**. There must be sufficient materials at the wellsite for packing the cores.

In general, cores shall be sent as soon as possible to the assigned Laboratory for analysis. If it is necessary to store cores temporarily at the well site, they must be stored in a cooled place. This is the responsibility of the WSG.

## **9.5 MUD LOGGING**

### **9.5.1 Responsibilities**

The general range of mud logging parameters shall be specified in the Mud Logging Contract. The requirement for and scope of mud logging services is specified in the Drilling Program

### **9.5.2 Mud Logging Preparation**

The following equipment checks must be made by the Mud Logging Contractor prior to commencing mud logging operations:

- The unit must meet the contract specifications. Deficiencies should be reported by the WGL and/or DSV to the DM who shall inform the Contractor's Representative.
- A full calibration of each sensor must be performed at the start of each well. Critical sensors may require more frequent calibration. Results of the calibration shall be reported on a standard calibration form for each specified sensor in the contract. Sensor calibration shall be verified at random by the WGL or DSV.

### **9.5.3 Monitoring**

All the parameters specified in the contract scope of services shall be recorded against time and depth and continuously monitored.

The mud logging unit personnel shall immediately inform the Driller or DSV of any of the following:

- Potential well control problems or drilling hazards.
- Any H<sub>2</sub>S detected.
- All unexplainable pit alarms and trend changes in the trip tank.
- Any significant increase in background gas or connection gas.
- Any significant divergence in mud density of the drilling fluid entering and leaving the well (when monitored).
- Any increase or decrease from the torque baseline (when monitored).
- An increasing or decreasing trend in standpipe pressure (when monitored).

### **9.5.4 Geological Service**

The full scope of geological services to be provided by the Mud Logging Contractor is contained in the scope of work in the contract. The following general practices should be followed:

- Cutting samples shall be taken so as to be representative of the interval drilled.
- Lithological analysis of the cuttings shall be performed on the washed samples with the aid of a binocular type microscope. Fluoroscopic analysis shall be carried out on all samples. Any samples indicating fluorescence shall be treated with solvents to detect hydrocarbons and establish the nature of the cut.
- Washed samples shall be dried and packed in envelopes marked with the date, well number and depth. Wet unwashed samples shall be put into sample bags lined with a

plastic bag at the time of collection at the shakers. Samples for geochemical analysis, if required, shall be packed in tins topped up with potable water. Bactericide shall be added before sealing the tin.

- Cutting lag time must be known at all times. A carbide lag time test should be performed every 12 hours or every 150 m whilst drilling or as requested by the WGL or DSV. The Driller must be informed before performing a lag test.

## 9.6 DRILL STEM TESTING

The Drill Stem Test (DST) is carried out to gather well/reservoir data and hydrocarbon/fluid properties, which may be essential for prospect/area evaluation and analysis. In general, tests are performed in open hole, and may use inflatable or conventional weight-set packers.

### 9.6.1 Responsibilities

All responsibilities for Drill Stem Testing are given in Section 9.2.

### 9.6.2 Standards

The following standards shall be adhered to during Drill Stem Testing:

- The surface pressure rating of the wellhead shall be at least 10% higher than the maximum of the following conditions:
  - Condition 1: SITHP for a gas filled tubing for the highest reservoir pressure to be tested.
  - Condition 2: The maximum surface pressure that is required to squeeze kill the test zone with the highest reservoir pressure to be tested.
- A Gamma Ray correlation will normally be performed on all inflate straddle tests
- DST intervals and packer setting depths and amount of water cushion shall be confirmed in writing prior to commencing the test. The DSV should refer to the DM in case of any queries.
- The type of separator required (if any) will be specified in the drilling program and confirmed by the WGL prior to the test.

### 9.6.3 Test Procedures and Guidelines

The following procedures and guidelines shall be adhered to during DST operations.

#### 9.6.3.1 General Guidelines

The following guidelines shall be implemented for all Drill Stem Tests conducted within GSLM operations:

- **DST tools shall not be opened during the hours of darkness.**
- All test string calculations and pipe additions shall be checked by the DSV for accuracy. A detailed DST schematic shall be sent to the DM for each test.
- After setting the packer element, check that the annulus is filled with drilling fluid before opening the test tool.
- Annulus fluid level shall be continuously monitored at all times while the packers are set.
- During unseating operations and during the first ten stands pulled, the hole shall be continuously monitored for swabbing.
- The DSV shall be on the rig floor during setting, valve opening, unseating, fluid recovery and initial POOH operations.
- The DST technician shall supervise the make up and tally of ALL the DST string components.
- Prior to commencing the DST, the following tests/checks shall be conducted:

### Pre DST Checklist

ITEM	CHECKED
Test interval(s) Packer depth(s) confirmed	
Jar Placement confirmed with testing engineer, DSV, DS and DE	
Water cushion confirmed with testing engineer, DSV, OGL	
Check if a Total Fire Ban is in place.	
Tasmanian Fire Service notified (if Total Fire Ban day) DSV/WGL	
JSA conducted	
Pre DST meeting held	
BOP tested within 14 days of DST	
DST equipment pressure tested and recorded	
Separator metering devices zeroed and calibrated	
Gauges and thermometers pre calibrated and checked against each other	
Detailed schematic of "as run" DST string completed	
Gamma correlation log available	
Flare line/pit visually checked	
Gas detector checked and functional	
Area around manifold/lines/separator cordoned off	
Mud pit volume totalisers functional/checked/calibrated for current pit volume	
Flow line sensor checked and functional	
Rig pumps lined up to fill annulus	
Signed by Toolpusher	Verified by Drilling Supervisor

**Table 60. Pre test checklist.**

- DST equipment shall be pressure tested as follows:
  1. Flow head to choke manifold - 3000psi      witnessed by DST contractor, verified by DSV.
  2. Choke manifold to separator - 1250psi      witnessed by separator contractor, verified by DSV.
  3. Separator – 80% of pressure rating of separator - witnessed by separator contractor, verified by DSV
- For DST's occurring on a Total Fire Ban day the Tasmanian Fire Service shall be notified. A fire truck may be required on location if requested by the TFS.
- A PTW shall be completed for the pressure test.
- A JSA shall be conducted.
- A pre well test meeting shall be conducted between the DSV, Contractor Toolpusher, Driller, WGL, testing and separator contractor.
- A detailed schematic of the DST components shall be forwarded to DM.
- Drilling jars will not normally be used in an open hole DST, however this should be assessed on a test by test basis. Consideration should be given to running the drilling contractor oil jars one stand from the top of the collars. This is to be discussed with the testing engineer, DM prior to implementation.
- Run only enough drill collars to operate the test tools plus a maximum of 25% in vertical wells. Use spiral drill collars and HWDP where possible.
- Assess risks of differential sticking and consider modifying DC placement (e.g. alternating stands of drill collars and HWDP).

### 9.6.3.2 DST Scheduling

- Drill Stem test Tools must not be opened during the hours of darkness.
- The test string must be reverse circulated prior to pulling out of the hole on ALL drill stem tests.

### 9.6.3.3 Running Guidelines

- The DSV shall ensure that DST tools are RIH at a controlled rate. DST tools shall be run slowly into the hole (approximately 1 1/2 mins per 27 m stand, 1 min per 18 m stand).
- The string shall not be rotated while running in or pulling out of the hole.
- If ANY tight hole is experienced DO NOT leave weight on the test string as the down hole valve will open and mud will enter the test string, lowering the level of the annulus.
- DO NOT rotate the drill string while running in. Rotation will inflate the packer Elements.
- Check the drill pipe periodically for surface air blow that will indicate fluid entering the drill pipe.
- Ensure that no bent pipe is run above the DST tools. Crooked joints will cause pipe whip while rotating to inflate the packers.
- Ensure that there is at least 3 m (10ft) above the rotary table when the slips are set prior to setting the packers.
- Lock swivel and establish drill string neutral, up and down weight prior to installing If low head etc and setting the packer (s).
- Testing contractor to calculate amount of water cushion. This must be confirmed by the DSV/WGL.
- Pressure test surface equipment.

### 9.6.3.4 Reverse Circulation / Pulling Procedures

2. Unseat the packer.
3. If safe to do so POOH until tools above any coals.
4. Rig up lines on top of drill string to test lines and DST test choke manifold
5. Rig up both mud pumps on to the annulus.
6. Make sure all choke valves are closed.
7. Close annular
8. Drop bar
9. Reverse out with choke closed until the FIRST sign of a pressure increase is seen (the mud catching up the annulus). Make sure someone is at the DST test
10. choke and the valve is opened before pressure exceeds formation breakdown.
11. Reverse circulate through the choke to the tank / flare. Reciprocate pipe slowly while Reversing

**Note:**

When reverse circulating without filling the pipe ensure that the U tube effect cannot



create an annulus pressure control problem from reservoirs higher up the hole.  
Reverse circulating will be subject to a separate permit to work..

While POOH after a DST, the following procedures will be followed:

- Ensure the annulus is full prior to commencing the trip
- During unseating operations and during the first ten stands pulled, the hole shall be continuously monitored for swabbing.
- Do not rotate the drill string as this will re-inflate the packers.
- POOH slowly as packers come to any known or suspected tight spots. Make sure that the test tools are not swabbing.

#### **9.6.4 DST Numbering Guidelines**

For the purpose of identifying drill stem tests, the following shall apply:

- Consecutive numbers shall be given to each tool run in the hole that is a successful test, or has reached bottom and an attempt has been made to open the tool.
- Tool runs that are held up on way in hole, i.e. unable to get through bridges, tools stuck etc., are not to be given a number. Identify the test as "Test Misrun, (specify intended interval)".
- Test numbering to be alpha numeric where more than one interval tested in a single run in the hole (e.g. 1A 1B etc.).
- DST data sheets shall be made up on numbered tests only. For tool runs not reaching bottom, the pressure charts and field data sheet are to be sent to the GSLM office. No distribution is required.
- The DSV/WGL shall check and verify the charts and data sheets. The DSV/WGL shall ensure all relevant data is intact and is sent to GSLM (as required).

## **CHAPTER 10 WELL CONTROL**

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## 10.1 OBJECTIVES

The purpose of this Chapter is to detail GSLM's requirements with regard to well control standards, procedures and practices. It outlines the minimum standards to be complied with, and describes and specifies the general procedures and practices to enable operations and engineering personnel to perform the following tasks:

Ensure all regulatory requirements are met.

- Ensure that well control equipment complies with the minimum standards shown in Appendix 3.
- Ensure that personnel are fully qualified, trained and prepared to shut-in and kill the well if a kick is taken
- Recognise and react to the warning signs of potential well kicks.
- Plan and conduct effective well killing operations.

Note that well design is based on the following kick tolerance criteria:

12 ¼" intermediate hole, 30 bbl maximum influx (gas)

8 1/2" hole 30bbl maximum influx (gas)

6 1/8" hole 30bbl maximum influx (gas)

These volumes are easily detected with the current rig monitoring equipment.

**Primary Well Control must be maintained at all times** (except when air or under-balanced drilling). Primary Well Control is defined as the use of drilling fluids of sufficient density to overbalance formation pore pressure and prevent entry of foreign fluids into the wellbore.

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

For each well control operation, all personnel must have a pre-assigned task appropriate to their function. All personnel also must be familiar with GSLM's well control standards and procedures.

The preferred method of secondary well control is the hard shut in. The preferred method of killing the well is to use the Wait and Weight method. Consideration should also be given to using the drillers method, particularly if surface volume may be a problem.

## 10.2 RESPONSIBILITIES

The well control responsibilities of each crew member during well killing operations are tabulated below.

Task	Performed by	Verified by
Ensure all preparations, personnel certification and drills meet GSLM's requirements	Drilling Contractor Toolpusher	DSV
Ensure emergency barite stocks are available	Drilling Fluids Engineer	DSV
Well control equipment tested and fully functional	Drilling Contractor Toolpusher	DSV
All personnel informed of their pre-assigned tasks	Drilling Contractor Toolpusher	DSV
Identify and shut in well flow: inform relevant supervisor	Drilling Contractor Driller	Toolpusher
Monitor shut-in and record kick data	Drilling Contractor Toolpusher	DSV
Callout well control specialist and specialised equipment if required	DM	CEO
Perform calculations and plan kill procedure	DSV / Toolpusher	DM
Preparation of kill mud (if not already available)	Drilling Fluids Engineer	DSV
Ensure well is secure, kill data collected and kill calculations are properly performed	DSV	DM
Liase with DM: provide information and request further assistance as required throughout operation	DSV	DM
Hold a pre-kill meeting with key personnel	Drilling Contractor Toolpusher	DSV
Supervise rig crew during kill	Drilling Contractor Toolpusher	DSV
Ensure adequate level of supervision on the rig floor at all times during kill procedures	Drilling Contractor Toolpusher	DSV
Co-ordinate activities of Driller and third party contractor personnel throughout operation	Drilling Contractor Toolpusher	DSV
Ensure well is secure: notify DM	DSV	DM

**Table 61. Responsibilities for Well Control**

### 10.3 GENERAL STANDARDS

The well control must be in accordance with the relevant Government regulations.

Company and Drilling Contractor personnel from Assistant Driller upward shall be in possession of a valid and recognised well control training certificate. All personnel shall be conversant with the GSLM standards and procedures as detailed in this chapter

The Drilling Contractor shall be responsible for performing pressure and function testing of all blow out prevention equipment and associated well control equipment that is provided within the terms of the contract between GSLM and the Drilling Contractor.

Prior to acceptance of a rig at the commencement of a drilling contract, GSLM shall review the documented BOP test standards, procedures and practices submitted by the Contractor, in order to establish whether these are in compliance with GSLM's required standards. A joint operating standard shall then be developed and approved by both parties.

An accumulator test shall be run prior to drilling the surface casing on the first well of a new program. This test shall confirm sufficient volume in the accumulator bottles to meet requirements in 10.4.4 below.

#### 10.3.1 BOP Pressure Testing

Pressure testing shall be performed using water and a plug type tester (where possible) on the entire BOP system as detailed in the text and table below. A cup type tester shall be used to pressure test the wellhead connection. If a test stump is available the BOP's should be tested on this while drilling surface hole.

Test	Frequency	Equipment
<b>Regular Tests</b>	Daily	The degasser shall be checked daily once the BOP's are installed. All preventers and manual closing controls shall be function tested. The blind rams shall be operated on each trip out of the hole
	14 days	Throughout all drilling, completion and workover phases, pressure testing shall be carried out once every 14 days from the day of the previous test.
<b>Casing</b>	New casing	BOP's shall be tested after prior to drilling out a new string of casing.
Operations Tests	Parts Changes	Pressure testing shall be undertaken whenever rams are changed or parts of the system have been replaced that may affect the pressure integrity.
	Major Repairs	After major repairs, and the first time the well control equipment is used for GSLM operations, the well control equipment shall be tested to its full rated working pressure.
	Drilling Program	All subsequent pressure tests shall be carried out in accordance with the Drilling Program.

**Table 62. Frequency of BOP Pressure Testing**

All pressure tests should be recorded on a pressure recorder. A test form must be completed after pressure testing the BOP's.

When testing the BOP stack, the casing side-outlets shall be open.

### **10.3.2 Diverter and BOP Equipment**

The following equipment tests and preparations must be adhered to at all times:

- Prior to commencement of operations, well control equipment shall be in full compliance with specifications as per the relevant contracts. BOP equipment will be fully operational at all times while drilling below the surface casing shoe. The BOP's shall be function tested daily and pressure tested every 14 days.
- For all drilling activities, full blow out prevention equipment shall be installed and tested before the surface casing shoe is drilled out.
- With BOP's in use, all line outlets, on the BOP's, exposed to well pressure shall have a double isolation arrangement.
- A diverter system shall be installed and tested on the conductor when drilling the surface hole.
- The working pressure of well control equipment shall exceed the maximum anticipated surface pressure to which it may be subjected.
- Only genuine spare and replacement parts shall be used on BOP and associated equipment.

## 10.4 EQUIPMENT STANDARDS

All BOP equipment used in GSLM activities shall comply with the standards described below.

### 10.4.1 General BOP Arrangement

All pressure contained components of the BOP stack and related equipment shall be constructed of material that meets the standards of NACE MR-01-75 and API RP-53.

The BOP stack should comprise of at least:

- One annular type preventer.
- Two ram type preventers.

The ram preventers shall have the following, sized for the Drilling Contractor's drill string.

One set of pipe rams, normally top rams (dressed w/- appropriate drill pipe or casing rams)  
One set of blind rams, normally bottom rams.

Stack configuration should ensure that the following objectives can be met.

- It must be capable of closing in on open hole and all tubulars programmed to be run through the BOP.
- It must allow for circulating out a kick with the drillpipe hung-off.
- It must allow for drillpipe to be hung-off and well secured.
- On re-entry, it must allow the well to be monitored for pressure and circulated, if required, prior to the rams being opened and the drill string recovered.
- It must allow for stripping operations to be conducted.



NACE MR-01-75

API RP-53

### Annular Preventers

Annular preventers shall have the capability of sealing around smooth surface objects of all sizes, including drill collars, Kelly's, drillpipe, casing, wireline and open hole. They shall also allow drillpipe and tool joints to be stripped through the preventer under pressure.

### Ram Preventers

The ram preventer shall seal only around a pre-designated shape, e.g. round objects (pipe and casing rams) or open hole (blind rams).

### Connections

Only welded, flanged or hub connections shall be used on any equipment or line rated above 2000 psi. Threaded connections must not be used.



#### 10.4.2 Choke and Kill System

The choke and kill system shall provide the valves and piping required to allow controlled circulation of the well under pressure. The choke and kill system shall include:

- A double valve arrangement on every line/outlet of the BOP.
- A hydraulically operated HCR valve included in the double valve arrangement on the (dedicated) choke line.
- Lines connecting the BOP stack to the choke manifold.
- A choke manifold.
- A flare line connected to the choke manifold.
- Hydraulically operated Choke Valve (preventor outlet)
- Each choke outlet on the BOP stack shall have one hydraulically operated, HCR type (High Closing Ratio), gate valve included in the double valve arrangement. This gate valve shall be set in the open position. Where dual-purpose kill/choke lines are used, each line shall have a hydraulically operated HCR valve included.

The following recommended practices for the installation of a choke (and kill) manifold shall be adhered to, as specified in API RP53 "API Recommended Practices for Blowout Prevention Systems":

- a) The assembly, connections, full opening valves, fittings, piping, etc., subject to well or pump pressure should be flanged, clamped or welded and have a rated working pressure at least equal to the rated working pressure of the BOP.
- b) All components should be selected in accordance with applicable API Specifications, taking into consideration pressures, volumes, temperatures and conditions under which they may be operated (i.e. gas, oil, drilling fluid, hydrogen sulphide, the environment, etc.).
- c) The choke manifold assembly and all choke lines shall be 3" nominal diameter or larger, have a minimum number of turns and be securely anchored. The dedicated kill lines shall be 2" nominal diameter or larger, and should be fitted with two valves and a non-return valve.
- d) The choke control station, whether at the manifold or remote from the rig floor, should be as convenient as possible and should include all monitors necessary to furnish an overview of the well control situation. The ability to monitor and control from the same location such items as standpipe pressure, casing pressure, pump strokes etc., greatly increases well control efficiency.
- e) Rig air systems should be checked to assure their adequacy to provide the necessary pressure and volume requirements for control of pneumatically or hydraulically operated chokes and valves. A redundant automatic choke control system, which may be manually operated, should be provided in the event that rig air becomes unavailable.
- f) Initial testing of the entire choke manifold assembly to the same test pressure as the preventers should be performed when the blowout preventer stack is nipped up to the wellhead, and thereafter whenever the blowout preventers are tested.
- g) Lines downstream of the choke manifold are normally not required to contain rated manifold working pressure, but should be tested during the initial installation.

Lines downstream of the choke manifold should be securely anchored, be of sufficient size to minimise friction and permit flow direction either to a mud/gas separator, ventlines, or to production facilities or emergency storage.

### 10.4.3 Degasser

The purpose of the gas separation equipment is to remove the gas from circulated out drilling mud so that the mud pumps operate effectively and the gas does not create a potentially explosive situation in the mud pits.

The mud gas separator shall be installed with a minimum 8" vent line, a minimum 4" choke manifold discharge line, and a mud seal of at least 6ft.

A small amount of gas in the mud will not significantly reduce the bottomhole pressure, but it may gas-lock the pumps and make the calculation of circulating pressures difficult or impossible.

### 10.4.4 BOP Control Systems

The accumulator must have sufficient volume to meet the following minimum volume criteria:

- Close the blind rams.
- Open the blind rams.
- Close the pipe rams.
- Open the pipe rams.
- Close the annular preventer.
- Open the annular preventer.
- Close one HCR valve.
- Open one HCR valve.

The BOP closing systems shall be capable of closing

- Each ram type preventer within 30 seconds.
- Annular preventers smaller than 20" within 30 seconds.

The accumulator volume must be checked to establish that the above criteria are met.

The following equation shall be used to calculate the total usable fluid volume for bottles.

$$USV = [PP] \times [NS] \times [VI] \left\{ \frac{1.02}{PP + 200} - \frac{1.06}{AP} \right\}$$

Where

USV	= Usable volume
PP	= Precharge pressure (usually 1215psia)
VI	= Bladder internal volume at precharge pressure
NS	= Number of bottles
AP	= Maximum operating pressure (usually 2815psia)

**Note:** Usable fluid volume is defined as the recoverable volume of fluid between accumulator operating pressure and 200psi above the pre-charge pressure.

#### 10.4.5 Drillstring BOP Valves

Components for shutting in the drill pipe internally are a basic part of well control equipment. All drill string BOP valves must have a pressure rating equal to, or greater than, the BOP stack.

The following drillstring BOP valves shall be available on the drill floor and ready for immediate use at all times:

- A full bore Kelly Cock shall be installed at the base of the kelly or top drive.
- A ball type stabbing valve (lower kelly cock), with connections or a cross-over to suit the workstring together with an operating handle for the valve, and removable handles for easy stabbing. This valve to be kept open and ready for installation.
- A circulating head with connections to suit the drill string
- Inside BOP (Gray type or equivalent).

#### 10.4.6 Kick Detection and Well Monitoring Equipment

A brief summary of the main kick detection and well monitoring equipment that should be available and fully operational is given in the text and table below.

Equipment	
Kick Detection Equipment	The following minimum kick detection equipment shall be available and fully operational: <ul style="list-style-type: none"> <li>• Flowline monitor</li> <li>• Active pit volume monitors</li> <li>• Gas detection at header box (mud logger responsibility)</li> <li>• ROP recorder</li> <li>• Trip tank with a system for accurately monitoring returns during tripping</li> </ul>
Mud Monitoring Equipment	All mud monitoring equipment (flo-show and PVT) shall be checked at various rates/volumes prior to drilling out casing and twice daily thereafter to ensure measurements indicated are correct and alarms are functioning.
Trip Tank	A trip tank shall be available and shall be complete with a mechanically operated indicator of the trip tank level visible from the Driller's position.
Gas Detection Equipment and Alarms	All gas detection equipment and alarms shall be functioning properly.

**Table 63. Kick Detection and Well Monitoring Equipment**

Continuous monitoring and recording of the following parameters shall be available on the drilling site for all wells:

- Active pit volume.
- Weight on bit and hook load.
- Standpipe pressure and choke pressure.
- Rate of penetration.
- Mud pump SPM.

## **Warning Signs - Possible Kick**

One or more of the following warning signs may be associated with the initiation of a kick, all can be caused by other factors. All require an immediate flow check.

### a. Increase in Pit Volume

An unexplained change in pit volume is the definitive indicator of a kick.

### b. Increase in Relative Flow

This is an increase in return flowrate while the pumps are still running at a constant output. This is often the first positive indicator that a kick is occurring, however an influx from a low permeability formation may be difficult to identify.

### c. Incorrect Hole Fill

If the volume of drilling mud required to fill the hole while pulling pipe is less than the calculated pipe displacement, formation fluids may be entering the wellbore.

### d. Gas Cut Mud

An increase in mud gas level may signify that formation gas has flowed into the well. It may simply be as a result of drilling a formation with a high gas content, however this could lead to an undesirable reduction in mud weight.

### e. Reduced Mud Weight

Mud weight reduction (or any significant change in other mud properties) may indicate a dilution of the mud by formation fluids - gas, oil or water.

### f. Drilling Break

A drilling break (ROP change) is due to a change in formation drilling characteristics, and may indicate increases in formation porosity, permeability and pore pressure. Breaks may be positive or negative.

### g. Decrease in Pump Pressure

A large influx of formation fluids, reduces the hydrostatic pressure in the annulus. The mud in the drill string can then U-tube into the annulus and the result is a reduction in pump load and pressure. The pressure reduction can cause the pumps to speed up. Normally if this indicator is seen, a serious kick has occurred and other indicators should be associated with it.

### h. Increase in Hookload

When an influx displaces the drilling fluid in the wellbore there should be a reduction in the buoyancy of the drill string which should be seen on surface as an increase in the hookload. An increase in hookload is not a reliable method of detecting a kick because it requires a large influx of low density fluid to produce a measurable hookload increase.

## **Pore Pressure & Underbalance Indicators**

### a. Background Gas

Background gas (BG) is the mud gas content that enters the system when the formation in which it was formerly contained is removed as cuttings. It is unrelated to pore pressure and will occur even in overbalanced drilling conditions. High BG levels which do not decrease with circulation may indicate a steady flow of gas from an underbalanced, low permeability formation.

b. Connection Gas

Connection gas (CG) is caused by the temporary reduction in bottomhole pressure during a connection, due to the combined effects of ECD loss and the swabbing effect of moving the pipe. CG is characterised as a peak above background gas, which is recorded one lag time after the connection.

The presence of CG indicates pore pressure is less than drilling ECD, and greater than mud hydrostatic during swabbing. Increase in CG magnitude on successive connections is an indicator of increasing pore pressure.

c. Trip Gas

Trip gas (TG) is gas which entered the hole during tripping. Trip gas will be detected in the mud on circulating bottoms up after a round trip. An increasing trend in the magnitude of trip gasses may indicate that pore pressure is increasing. Significantly high Trip gas may indicate a close to balance situation exists in the hole.

d. Shale Cavings

Any cuttings that have not been created by bit action are termed 'cavings'. Pressure cavings are long, splintered and angular, and occur when overpressure causes the shale borehole wall to crack and burst into the well.

e. Decrease in Shale Density

Shale density normally increases with depth but this trend is reversed in abnormally pressured zones. The density of the cuttings is measured and plotted versus depth. Any deviation from the normal trend line may be interpreted as a pore pressure change.

f. Temperature Measurements

A change in temperature gradient is often associated with an abnormally pressured formation. The limitation of this method is that the mud temperature can usually only be measured on surface and is subject to external influences.

## 10.5 BOP SYSTEM TESTING AND INSPECTION

The BOP system shall be pressure tested according to the principles below. Individual well programmes may require variations to test pressures.

- All BOP tests shall be tested to a low and high pressure. The actual pressure required will be given in the drilling programme. The criteria for the minimum pressure required for the high pressure test will be the greater of:
  - a) Maximum surface pressure assuming gas from TD to surface.
  - b) Surface pressure assuming gas from last casing shoe to surface with a 16 ppg fracture gradient at the shoe.
- All BOP system components shall be tested to a low pressure test of 200 psi prior to the required final high pressure test value.
- All BOP system components should be subjected to differential test pressures in the direction of pressure that will occur in service.
- The annular preventers should be pressure tested first, in order to allow them additional time to relax prior to pulling the test tool.
- Ensure valves are open downstream of the component being pressure tested.
- Maximise the number of components being tested on each test in order to minimise the number of tests.
- Ensure the downstream side of all preventer choke and kill valves are pressure tested.
- The criteria for a satisfactory test shall be a minimum of five minutes with a decline of less than 5% of test pressure.
- Test fluid volumes pumped and bled back must be carefully monitored and recorded. This is particularly important when testing against the casing pack-off to avoid pressuring the casing annulus and risking casing collapse. The control panels used should be alternated on each function and pressure test.
- All pressure tests shall be witnessed and signed by the DSV. Pressure tests shall be recorded on a chart recorder, reported on the Daily Drilling Report (Form F-301), the IADC Tour Sheet and the BOP Test Sheet (Form F-201).

### 10.5.1 Accumulator Function Test Requirements

- All Systems shall be cycled from the normal operating position and times recorded.
- Remote systems shall be checked, cycled, timed and recorded every day.
- Accumulator charging pump output will charge the accumulator system from precharge pressure to operating pressure in 15 minutes or less.
- Accumulator pump systems shall be functioned every tour while drilling by the driller.
- Rig air pressure systems shall be bled off every day to function test fail safe systems.
- Should any of the above tests indicate faulty equipment, the equipment must be repaired immediately and re-tested before drilling operations resume.

### 10.5.2 Maintenance and Inspection

The following general requirements for maintenance, inspection and testing of BOP and associated equipment shall be implemented as follows:

- a) A BOP body pressure test shall be carried out once a year on the test stump, in accordance with the manufacturer's specification for such a test.
- b) BOP's shall undergo a regular major overhaul and inspection, depending on the type of work and period in use. Periods between checks shall not exceed 5 years.
- c) BOP hydraulic operating lines shall be tested to the maximum accumulator manifold pressure when newly installed and during every regular BOP stack test, by opening the Koomey KR bypass valve. The control lines to the annular preventer shall be tested once per well to the maximum operating pressure. The control lines are to be disconnected from the annular preventer in order to avoid damaging the annular preventer rubber.
- d) Ensure the manufacturer's BOP operating manual is followed and no alterations are made to the BOP equipment without written consent from the manufacturer. Re-certification may be required after making equipment alterations.
- e) Only genuine spares/replacement parts shall be used on BOP and associated equipment.
- f) A maintenance schedule and checking procedures for BOP's shall be available on the drilling location and workshop.
- g) Records of maintenance both scheduled and unscheduled shall be kept in a BOP history file at the Contractor's office. A copy of this file should also be kept at the rig.

## **10.6.0 WELL CONTROL DRILLS**

Well control drills shall be initiated by the DSV and performed to ensure that the crews are adequately trained and prepared to implement well control procedures correctly. They shall only be conducted when they do not complicate ongoing operations. A kick should be simulated by manipulation of a primary kick indicator such as the tank level indicator or the flowline indicator.

The drills described below include the full sequence of shutting in a well, however the critical reaction time shall be recorded up to the point when the designated person is about to begin the closing sequence of the annular preventer(s).

It shall be necessary to repeat the drills each tour until the DSV is satisfied that the crews are adequately trained and responsive.

### **10.6.1 Well Control Drill Reporting**

The following shall be recorded in the IADC tour report and the Daily Drilling Report:

- The types of drill conducted and the reaction time from the moment the kick is simulated until the crew is ready to start the closing procedure. The operation shall be recorded as "Well Control Drill".
- The total time taken to complete the drill.

### **10.6.2 Well Control Drills**

The following sections describe the tasks required to perform four types of well control drills. These four drills are also displayed schematically in the Appendices at the end of this Chapter.

Note that the shut-in drill listed below assumes a hard shut-in technique for on-bottom drilling.

#### **Kick Drill Condition 1 (On Bottom Drilling)**

1. Stop rotary. Raise kelly and slow down pump (Stop pump when lower kelly cock and first tool joint are above table)
2. Close annular preventer.
3. Open choke line (HCR valve).
4. Record drill pipe and casing pressures.
5. Record time to complete drill.

#### **Kick Drill Condition 2 (While Tripping the Drill String)**

1. Position upper tool joint above rotary table and set slips.
2. Install an inside BOP to the string; close the valve.
3. Close annular preventer.
4. Open choke line (HCR valve).
5. Install kelly and open inside BOP.
6. Record drill pipe and casing pressures.
7. Record time to complete drill.



### **Kick Drill Condition 3 (While Out of Hole)**

1. Close blind rams.
2. Open choke line (HCR valve).
3. Record casing pressure.
4. Record time to complete drill.

### **Kick Drill Condition 4 (While Drill Collars are Adjacent to Preventers)**

1. Position upper drill collar box at rotary and set slips.
2. Install an inside BOP to the string; close the valve.
3. Close annular preventer.
4. Open choke line (HCR valve).
5. Record drill pipe and casing pressure.
6. Record time to complete drill.

**Note:** If only 1 stand of drill collars remains to be recovered, the stand should be removed and the well treated as in Condition 3.

### **10.6.3 Routine Daily Precautions**

Mud engineer to ensure adequate chemical supplies to control the well are available.

Slow Circulating rates (SCRs) for each pump must be taken (as a minimum) as shown below:

- Once per tour or at 150 m intervals during the tour.
- At bit and/or BHA changes.
- After significant changes in the drilling fluid density or rheology.
- Prior to drilling the casing shoe or transition zones.

Reporting shall be on the IADC and Daily Drilling Report and must include:

- A minimum of two pump rates.
- The SCRs chosen should not be less than 0.5 bbl/min and not greater than 4 bbl/min.
- The pressures must be recorded using the gauge to be used during well kill operations.
- SCRs shall be taken on all pumps and at the same rates.

### **10.6.4 Well Control Data Reporting**

Basic well data must be recorded accurately at regular intervals and be easily available. This must include the following:

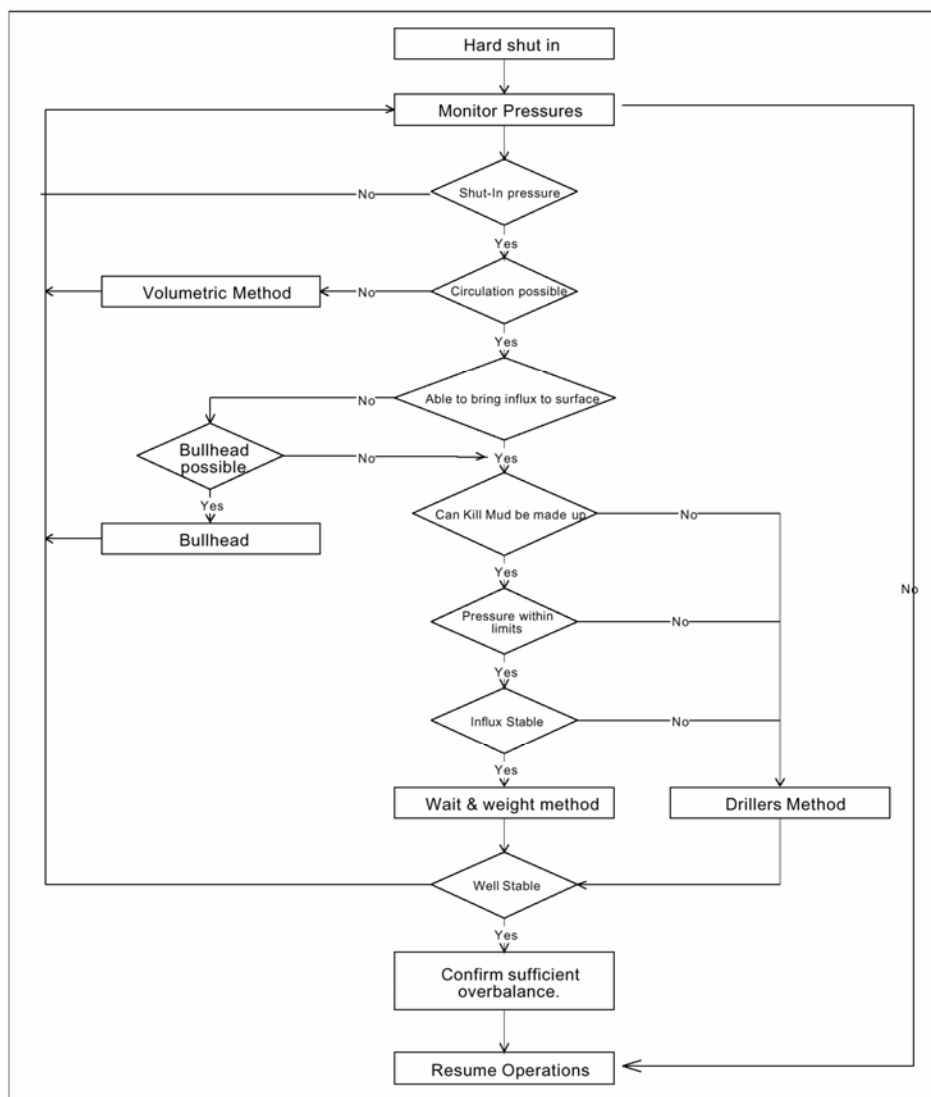
- SCR Pressure/Rate Data (see above).
- Leak Off Test as given in Chapter 10.9 of this Manual.
- Maximum Allowable Annular Surface Pressure , and see Appendix I, this Chapter.
- Completion of Killsheet by the DSV, Driller and Toolpusher.

## 10.7.0 WELL CONTROL PROCEDURES

- The preferred GSLM shut-in method of well control is 'hard' shut-in.
- The preferred method of Secondary Well Control is the Wait and Weight Method (Refer 10.7.3). Consideration should be given to using the drillers method (Refer 10.7.5) in situations where mud mixing and handling may be a problem.
- Other approved methods such as Bullheading and Volumetric Methods (see following text) shall only be utilised in special cases.

The appropriate method to be used is decided after consultation with the DSV and DM. The following flowchart shall be used as a guide.

*Well Control Method Selection - Decision Analysis*



**Figur 10. Well Control Method Selection – Decision Analysis**

### 10.7.1 Well Shut-in Procedures

The following sections describe the tasks required to perform three different shut-in procedures. These three procedures are also displayed schematically in the Appendices at the end of this Chapter.

**Note:** that the shut-in procedures listed below assume a hard shut-in technique.

### **Shut-in Procedure (While Drilling or Making Connection)**

If well is flowing:

1. Stop rotary.
2. Raise kelly and slow down pump.(Stop pump when lower kelly cock and first tooljoint are above table).
3. Close annular preventer.
4. Open choke line (HCR valve).
5. Read and record:
  - a) Shut-in Drill Pipe Pressure (SIDPP)
  - b) .Shut-in Casing Pressure (SICP).
  - c) Pit volume increase.
6. After recording shut-in pressures proceed to kill well as per Section 10.7.3.

### **Shut-in Procedure (Tripping with Drill Pipe) - Flow Chart**

1. Position upper tool joint above rotary table and set slips.
2. Install an inside BOP to the string; close the valve.
3. Close annular preventer.
4. Open choke line (HCR valve).
5. Read off the SICP. If this value is less than 1000psi (or the MAASP, whichever is the lower pressure), reduce pressure on annular preventer, lubricate element and strip back in (if possible).
6. When the string is stripped in to maximum allowable SICP, stab in kelly and establish SIDPP, record new SICP.
7. After recording shut-in pressures proceed with well kill procedures.

**Note:** If it is not possible or feasible to strip drillstring back to bottom, the well may require to be killed using other techniques, the preceding may help in deciding which method to use (eg Bullheading: See Section 10.7.7).

### **Shut-in Procedure (Tripping with Drill Collars)**

1. Position upper drill collar box at rotary and set slips.
2. Open choke line (HCR valve).
3. Close annular preventer if installed (if not installed, then add 1 joint or 1 stand of drill pipe to collars, and run back in hole; close pipe rams)
4. Install an inside BOP to the drill collar or drill pipe box.
5. Secure string at derrick floor.
6. Close inside BOP valve.
7. Shut in at choke.
8. Close manual valve upstream of choke.
9. After recording shut-in pressures proceed with well kill procedures.

**Note:**

- a) If only 1 stand of drill collars remains to be recovered, the stand should be removed and the well shut in.
- b) Drill collars could be dropped into the hole depending on potential severity of blowout.

### 10.7.2 Well Control Data and Calculations

The following data shall be monitored and recorded on the Well Control Operations log at the drill floor throughout a well kill operation.

- Times.
- The shut-in casing pressure (SICP).
- Shut-in Drill pipe pressure (SIDPP).
- Active pit volume.
- Description of events, including all pressures at one minute intervals until they have stabilised.

Well Calculations shall be made on the Killsheet and submitted to the DSV for approval. The DSV, Toolpusher, and Driller shall independently prepare a kill sheet for verification. These shall be used by the DSV to ensure accuracy of the well control calculations.

### 10.7.3 Wait and Weight Method (Well Kill Procedure)

The following well kill procedure is also given schematically in the Appendices at the end of this Chapter.

1. Zero stroke counter. Start the pump slowly while simultaneously opening the remote adjustable choke.
2. Increase pump speed to the selected kill pump rate while maintaining casing pressure constant.
3. When the pump is up to speed, read and record the Initial Circulating Pressure (Pic). In all cases use the actual Pic rather than the calculated value.
4. Maintain the drill pipe pressure as per the drill pipe pressure schedule on the Kill sheet. Maintain constant pump speed throughout circulation.
5. When the kill mud reaches the bit, maintain the drill pipe pressure constant at the Final Circulating Pressure (Pfc) by choke adjustment until kill mud reaches surface.
6. When kill mud reaches surface, shut down the pump and close the choke. Read and record SIDPP and SICP.
7. If drill pipe and casing pressures are recorded, bleed-off pressures to check for trapped pressure. If the well is not dead, resume circulation to ensure uniform kill mud throughout wellbore. If drill pipe and casing pressures equal zero, flow check through the choke line.
8. Circulate wellbore conventionally and add a suitable overbalance to the mud weight.

**Note:** If it is necessary to stop pumping at any time during the well circulation, immediately shut-in the well. To resume pumping, maintain kill line (wellhead) pressure constant while bringing the pump up to speed to account for choke line pressure drop. Pic shall be re-checked as per Step 3, and the drill pipe schedule adjusted if necessary.

#### 10.7.4 Concurrent Method

The Concurrent Method is a variation of Wait and Weight Method. It is used when it is not possible to weight up the mud system to kill weight at once, but when the Driller's Method will result in an unacceptably high well bore pressure.

The mud weight is increased in stages until the well is full of kill weight mud, with each new weight being circulated all the way to surface. A new drill pipe schedule is constructed for each circulation as per the Wait and Weight Method.

#### 10.7.5 The Driller's Method (Well Kill Procedure)

The Drillers Method is described below. The procedure has been subdivided into the procedure during the first circulation and the procedure for the second circulation.  
The Driller's Method Well Control Schematic Procedures.

##### First Circulation

The procedure for the first circulation is as follows:

1. Zero stroke counter. Start the pump slowly while simultaneously opening the remote adjustable choke.
2. Increase pump speed to the selected kill pump rate while maintaining casing pressure constant to account for choke line pressure drop.
3. When the pump is up to speed read and record the Pic. The actual Pic should be used rather the calculated Pic.
4. When the influx has been circulated out of the well stop the pump and shut the well in at the choke. Read and record SICP and SIDPP. If the influx has been totally removed SICP should equal SIDPP.

**Note:** A kill graph is not required for the first circulation, since drill pipe pressure will be maintained constant at Pic after bringing the pump up to speed. Pic should be estimated prior to commencing circulation:

$$Pic = PSCR + SIDPP \text{ (psi)}$$

##### Second Circulation

The procedure given below is also shown schematically in the Appendices at the end of this Chapter.

**Note:** The standpipe pressure at the start of the second circulation (Pic) may be taken as the actual circulating pressure at the end of the first circulation.

1. Prepare Kill Graph. The circulating pressure when the kill mud reaches the bit shall be calculated as follows:

$$P_{fc} = P_{ACTUAL} \times \frac{\text{Kill Mud Weight}}{\text{Original Mud Weight}} \text{ (psi)}$$

The standpipe pressure versus volume pumped or time should be plotted. Standpipe pressures should include a safety margin (use 150psi) to allow for choke operator reaction time.

The graph shall be prepared as follows:

- i. Plot the initial standpipe pressure ( $P_{ic}$ ) at the start of the second circulation.
    - ii. Plot the standpipe pressure when kill mud has reached the bit ( $P_{fc}$ )
    - iii. Connect the two points with a straight line. This line represents the standpipe pressure whilst pumping the kill mud from the surface to the bit.
  1. Start well killing procedure by zeroing the stroke counter.  
Start the pump slowly while simultaneously opening the adjustable choke.
  2. Increase pump speed to the selected kill pump rate while maintaining casing pressure constant to account for choke line pressure losses.
  3. After the pump is up to speed, read and record the  $P_{ic}$ . The actual  $P_{ic}$  should be compared to the calculated value, and if required, adjustment made to the drill pipe pressure schedule to account for any differences between the two values.  
In all cases, use the actual  $P_{ic}$  rather than the calculated value.
  4. Maintain the drill pipe pressure as per the drill pipe pressure schedule.  
Maintain constant pump speed throughout circulation.
  5. When the kill mud reaches the bit, maintain the drill pipe pressure constant at the  $P_{fc}$  by choke adjustment until kill mud reaches surface.
  6. When kill mud reaches surface, shut down the pump and close the choke. Check drill pipe and casing for pressure. If drill pipe and casing pressures are recorded, bleed off pressures to check for trapped pressure. If the well is not dead, resume circulation to ensure uniform kill weight mud throughout wellbore.
  7. If drill pipe and casing pressures equal zero, flow check through the choke line.
  8. Circulate wellbore conventionally and add a suitable overbalance to the mud weight.
- Note:** If it is necessary to stop pumping at any time during the well circulation, immediately shut-in the well. To resume pumping, maintain kill line (wellhead) pressure constant while bringing the pump up to speed to account for choke line pressure drop.  $P_{ic}$  shall be re-checked as per Step 3, and the drill pipe schedule adjusted if necessary.

### 10.7.6 Static Volumetric Method (Well Kill Procedure)

The Static Volumetric Method is used to control rising well pressures due to a migrating influx. It is a constant bottomhole pressure method. It can only be used if the influx is migrating. It is an alternative to a circulation kill method which may be used in the following circumstances:

- Drill string out of hole.
- Drill string cannot be stripped to bottom.
- Washed out or parted drill string.
- Plugged bit.

#### Static Volumetric Control Procedure (Casing Pressure Method)

The procedure given below is also shown schematically in the Appendices at the end of this Chapter.

1. Prepare the Volumetric Control Worksheet for the kill operation. The influx migration and hydrostatic pressure equivalent shall be determined as shown in the table below.

Calculation	Equation	Abbreviations
Influx Migration Rate	$MR = \frac{(P2 - P1) \times 19.25}{MW \times T}$	MR = Migration Rate up constant cross Section annulus (ft/hr) P1 = Surface pressure at start of time Interval T (psi) P2 = Surface Pressure at end of time Interval T (psi)
Hydrostatic Pressure Equivalent	$HPE = \frac{53.44 \times MW}{(dh^2 - do^2)}$	MW = Mud weight (ppg) T = Time interval between Pressure Readings (hours) HPE = Hydrostatic Pressure Equivalent of 1 barrel of mud in the annulus (psi) dh = Hole or Casing ID (in) do = Drill String OD (in)

**Table 64. Influx Migration Rate and Hydrostatic Pressure Equivalent Calculations**

2. Allow casing pressure to increase by an overbalance margin plus an operating margin. The suggested value for each of these margins is 100psi.
3. Bleed off a volume of mud from the annulus which is equivalent to the operating pressure margin. Maintain the casing pressure constant as the mud is bled from the well. This will be a very slow process because the rate of expansion is governed by the migration rate calculated in Step 1. This will result in the formation remaining over- balanced by the overbalance margin. Use a manual choke to ensure adequate control. Record all volumes and pressures on the Volumetric Control Worksheet.
4. Repeat steps 2 and 3 above. Do not vent gas when the influx reaches surface as the bottomhole pressure may decrease and a further influx may be taken.
5. Prepare high density mud to pump into the well. Calculate the hydrostatic pressure equivalent for one barrel of lubricating mud in the annulus using the same equation outlined in Step 1.
6. Line up to pump lubricating mud down the kill line.

7. Pump lubricating mud into the well until pump pressure reaches a predetermined limit based on MAASP (Maximum Allowable Annulus Surface Pressure). Record volume pumped.
8. Allow the lubricating mud to fall through the influx as the well is left static.
9. Bleed gas from the well to reduce the casing pressure by an amount equivalent to the hydrostatic pressure of the lubricating mud pumped into the well. Ensure returns are lined up through the poor boy degasser and the volume of any mud bled back is recorded. Shut-in immediately when mud returns are noted when bleeding off.
10. Repeat Steps 5 and 6 until all gas has been vented from the well.

#### **Static Volumetric Control procedure (Drill Pipe Pressure Method)**

This procedure shall only be used in the following circumstances:

- Pipe on bottom.
- No drill string float (ported or un-ported) installed.

The procedure given below is also shown schematically in the Appendices at the end of this Chapter.

1. Determine the migration rate as shown in the table above.
2. Allow the drill pipe pressure to build up by an operating margin of c. 100-200psi overbalance margin. This will depend on the MAASP.
3. Bleed mud from the choke manifold until the drill pipe pressure has reduced to the original stabilised shut-in value plus the overbalance margin.
4. The mud must be bled very slowly; the delay time may be considerable before drill pipe response is seen.
5. It is essential that the bottomhole pressure is not allowed to fall below formation pressure.
6. Continue Steps 2, 3, 4 and 5 until the influx has migrated to surface. Do not bleed off gas.



### 10.7.7 Bullheading

Bullheading can be considered when:

- Large gas influx that will result in an excessive volume of gas or excessive pressure at the surface if circulated out.
- Pipe is off bottom and cannot be stripped in.
- No pipe in the hole.

Factors which may affect the feasibility or success of bullheading:

- Discrete or strung out influx. An influx sustained while drilling may be contained in a large mud volume that will be difficult to squeeze away.
- MAASP due to formation fracture pressure and equipment rating.
- Formation permeability.

#### Bullheading Procedure

The procedure given below is also shown schematically in the Appendices at the end of this Chapter.

1. Assess the migration rate as described in Section 10.8.6
2. Calculate MAASP for the current mud weight.
3. Establish injection pressure by pumping down the annulus at a slow rate.  
Keep pump rates constant and plot the injection pressure versus the volume.
4. Do not exceed MAASP.
5. If injection pressure continues to increase, stop pumping and observe.  
A decrease in pressure indicates successful bullheading.
6. Continue pumping to over-displace the top of the influx to TD by 50%.
7. Shut down and observe the well.
8. Raise mud weight (if necessary), if possible circulate using Wait and Weight Method until annulus is clear of influx.

### 10.7.8 Stripping

The procedure described in this section is the Combined Stripping and Volumetric Technique that maintains constant bottomhole pressure while the pipe is stripped through the annular. The principle used to accomplish this is a volume balance of the wellbore; for every barrel of pipe stripped in the hole a barrel of mud is bled off.

The following text summarises the calculations performed prior to stripping in. This procedure is also shown schematically in the Appendices at the end of this Chapter.

#### Maintaining Constant Bottom Hole Pressure

The pipe volume added to the well will increase the bottomhole pressure if mud volume is not bled off. Bottomhole pressure will also increase due to influx migration during the time period that stripping operations are being conducted. As the BHA enters the influx, an additional increase in bottomhole pressure can occur. These effects must be accounted for in order to maintain constant bottomhole pressure.

### Determine Pipe Volume Effect

1. Calculate the pipe volume (per stand of pipe stripped in) as follows:

$$V = LS (Ddp + Cdp)$$

Where	V	= Volume per stand (bbls).
	LS	= Average stand length (ft).
	Ddp	= Drill pipe displacement(bbls/ft).
	Cdp	= Drill pipe capacity (bbls/ft).

2. When each stand has been stripped in, bleed off the calculated required volume of mud from the annulus (i.e. during connection). This method can provide a clearer indication of when the BHA enters the influx.

**Note:** A float must be used and the pipe filled when RIH.

Alternatively, it may be preferred to bleed off volume as the pipe is being run, to maintain a more constant pressure regulation process, or if the pressure increase resulting from adding one stand approaches or exceeds MAASP.

3. If pipe is being stripped out of the hole, the required volume of mud should be added continuously as the pipe is being pulled to ensure the bottomhole pressure does not drop and thereby allow additional influx to enter the wellbore.

### Determine Influx Migration Effect

When stripping operations take a significant time to complete, influx migration effects must be considered. Usually, the volume of mud to be bled for influx migration is small relative to the volume bled off to compensate for the addition of pipe into the hole.

Influx migration can be detected by:

- A gradual increase in surface pressure even though the correct volume of mud is being bled from the well.
- Surface pressures increasing when the pipe is stationary.

The volume of mud to be bled-off for influx migration can be calculated using the Hydrostatic Pressure Equivalent formula given in Section 10.7.6

### Determine Effect of BHA Entering Influx

When the BHA is run into the influx, the surface pressure will increase at a higher rate than prior to entering the influx. This is due to the displacement of the influx around the BHA extending the influx height and hence lowering the total hydrostatic pressure in the annulus.

Whilst balancing formation pressure, the surface pressure therefore increases. It is very important to recognise this effect and to ensure that the casing pressure is not bled off to compensate for the increase in pressure.

The maximum possible pressure increase due to the BHA entering the influx shall be calculated as follows:

$$PMI = \frac{(53.44)(MW - IFG)}{dh^2} V \left\{ \frac{dh^2}{dh^2 - do^2} - 1 \right\}$$

Where

PMI	= Maximum Pressure increase (psi).
MW	= Mud weight equivalent (ppg)
IFG	= Assumed influx fluid density (ppg)
V	= volume per stand of pipe (Bbls) as calculated above
dh	= Hole size (in)
do	= BHA OD (in)

### Stripping Procedure

This procedure is also shown schematically in the Appendices at the end of this Chapter.

1. Install inside BOP valve above drill pipe stab-in valve. Open stab-in valve.
2. Reduce annular closing pressure to the recommended pressure for stripping pipe at the actual casing pressures. Allow a slight leakage through the preventer while stripping.
3. The pipe should be slowly lowered through the annular while the annular surface pressure is accurately monitored. Reduce running speed when passing tool joints through the annular.
4. Bleed the required volume of mud from the well during each connection unless MAASP pressure limitations dictate that it be bled more frequently. Complete the Stripping Worksheet for each stand run and each time volume is bled.

**Note:** Maintain an overbalance of 50 to 200psi at all times while stripping, unless formation integrity will not be able to take such an overbalance.

5. Fill the pipe every five stands with original weight mud.
6. Strip to bottom or desired depth to kill well.

### Changing Rams etc. while stripping

The combination wear bushing/test tool designed for the compact wellhead system is capable of being hung off on the wear bushing. In the event of a serious leak in the annular preventer or pipe rams therefore, it is possible to:

1. Strip in the combination tool using the annular and pipe preventer.
2. Land out on the wear bushing.
3. Back out the running string above the combination tool (this connection must be made up "soft").
4. Close the blind rams above the tool.
5. Effect necessary repairs while monitoring/control pressures.
6. Retrieve the combination tool and strip out of hole.
7. Resume operations.

## 10.8 WELL CONTROL PROBLEMS

Conventional well control procedures are based upon the assumption that all of the well control equipment operates as designed and the wellbore is able to withstand the imposed pressures. Mechanical problems and formation fracturing, however, occurs occasionally during well killing operations causing complications with conventional procedures.

Careful consideration must be given to the available well data before selecting an alternative procedure. The figure below outlines the possible cause of problems for several unexpected changes in surface measurements.

	DRILL PIPE PRESSURE	CASING PRESSURE	DRILL STRING WEIGHT	PIT LEVEL	PUMP S.P.M.
LOSS OF CIRCULATION	↓	↓	↑	↓	↑
CHOKE PLUGS	↑	↑	NO CHANGE	↓	↓
BIT NOZZLE PLUGS	↑	NO CHANGE	NO CHANGE	NO CHANGE	↓
BIT NOZZLE WASHES OUT	↓	NO CHANGE	NO CHANGE	NO CHANGE	↑
PUMP VOLUME DROPS	↓	↓	NO CHANGE	NO CHANGE	NO CHANGE
HOLE IN DRILL STRING	↓	NO CHANGE	NO CHANGE	NO CHANGE	↑
GAS FEEDING IN	NO CHANGE	↑	↑	↑	↑
CHOKE WASHES OUT	↓	↓	NO CHANGE	↑	↑
GAS REACHES SURFACE	NO CHANGE	↑ THEN ↓	↓	↓	NO CHANGE
SYMBOLS: ↑ INCREASE    ↓ DECREASE    ■ MAJOR    □ MINOR					

**Figure 11. Well Control Problem Indicators**

### 10.8.1 Well Control in Horizontal Wells

Although the kill calculations are identical for straight, deviated and horizontal wells (true vertical depths used in all cases) and the well control procedures are based on the same principles, these considerations should be implemented during both the planning and operational phases of a horizontal drilling programme.

#### 1. Tripping

In general, the bottom hole assemblies used to drill horizontal wells are not as likely to cause swabbing as those run in vertical wells. However, substantial reservoir intervals may be exposed, increasing the potential for swabbing and making induced kicks greater than in a vertical well.

Extreme caution shall be exercised when returning to bottom following a trip. The horizontal section of the wellbore could be partially or completely filled with reservoir fluids despite the well being static (i.e. not flowing). It is therefore recommended that bottoms up be circulated through the choke manifold and degasser prior to drilling ahead.

## 2. Influx Volume and Nature

In the event of a kick in a horizontal well it is virtually impossible to determine the nature of the influx (i.e. oil, gas, water) due to equivalent shut in drill pipe and casing pressures. It may be difficult to validate data obtained during a kick and hence it is recommended to assume a gas influx at all times.

## 3. Productivity

The economic rationale responsible for the implementation of a horizontal drilling programme should be kept in mind when considering well control issues. The enhanced productivity and amount of reservoir section exposed tend to increase the rate of influx. Rig personnel should be particularly cognisant of well control procedures while drilling through the pay zone, especially if drilling at the balance point with non-damaging brines. Well control should never be ignored due to directional control problems.

### **10.8.2 Gas Hydrates**

Gas hydrates can present serious problems during well control operations. Gas hydrates are complex crystalline structures of hydrocarbons and water having the appearance of hard snow. They can form at temperatures above the normal freezing point of water under certain pressure conditions. This formation process is accelerated where there are high gas velocities, pressure pulsations or other agitation's which cause mixing of the hydrate components.

The conditions for hydrate formation can be predicted. These pressure and temperature conditions can exist in a well control operation where low geothermal gradients exist, or downstream of a pressure drop in the system, i.e. choke. This can result in plugging of surface lines downstream of the choke.

Prevention of gas hydrates can be accomplished by maintaining pressures and temperatures outside the hydrate range, or by suppressing the hydrate formation temperature by injecting glycol into the gas stream. In well control operations pressure or temperature control methods for gas hydrate prevention are usually not possible, therefore use of glycol injection is recommended.

A gas hydrate contingency plan should be formulated for all wells where the potential exists for gas hydrate formation. The plan should provide a method of injecting glycol at the BOP stack.

A suggested method of accomplishing this is to pump glycol down the kill line with the cement unit and slowly injecting it into the well as the gas approaches surface and enters the choke line.

### 10.8.2 Cement Plug

If the well can not be controlled by conventional means it may be necessary to cement off the over-pressured zone. The cement slurry design should take account of the following factors:

- Spacer type and volume must prevent contamination during displacement.
- Surface lines must be free of potential contaminants.
- Gas channelling must be minimised by application of appropriate cement recipe technology.
- Slurry volume must be sufficient to allow for displacement into the formation.
- Slurry density must be sufficient to provide overbalance during displacement

The use of cement offers little chance of recovering the drillstring once cement is displaced up the annulus, particularly around stabilisers in the BHA. It must also be considered that there is a poor chance of achieving adequate cement isolation in the annulus between the BHA and hole. In addition, cementing will often result in the bit nozzles becoming plugged preventing further cementing attempts without resorting to perforating the drill pipe. Consequently cement plugs should be considered a last resort.

### 10.8.4 Barite Plug

This is a mixture of barite and water or diesel. The objective is to utilise the rapid settling effect of the barite in water, in the absence of any viscosifier, to rapidly form an impermeable barrier to flow.

The following is a guide to the typical recipes for 1 barrel of barite plug. The mud engineer should perform pilot testing prior to pumping:

Required Density (ppg)	Volume of Freshwater Required (bbl)	Amount of Barite Required (lbs)
17.9	0.642	530
20.0	0.560	643
21.0	0.528	695
21.93	0.490	740

**Table 65. Barite Plugs, Barite-Water Mix for Water Based Muds**

Lignosulphonate thinner at 0.4ppb and caustic should be added to keep the barite particles separate.

#### Displacement Procedure

1. The barite slurry should be mixed by adding the barite to previously prepared water and thinners.
2. The slurry must then be pumped immediately unless continuous agitation is possible.
3. The slurry should be pumped at a higher rate than the kick rate and no less than 10 bbl/min with both the cement unit and rig pump tied into it.
4. After the plug has been displaced, it should be verified that flow has been stemmed by shutting in the well and observing pressures.
5. If the flow has stopped and a second plug is not required then the pipe will be pulled above the plug and circulated clean.

## **10.9 FORMATION INTEGRITY TESTS**

The hesitation method shall be used for the conduct of all Formation Integrity Tests. This involves pumping a small amount, waiting for the pressure to stabilise before repeating the process until the maximum test pressure is achieved. The test pressure shall be limited to a maximum pressure that does not exceed the lowest of the following:

- Actual leak-off pressure.
- The pressure specified in the Drilling Programme (typically the pressure required to give required kick tolerance or 80% of casing burst pressure).
- The wellhead test pressure.
- The BOP test pressure.
- A maximum pressure of 0.8 psi/ft at the casing shoe.

### **10.9.1 Responsibilities**

All responsibilities for Formation Integrity Testing are given in Section 10.2

### **10.9.2 Testing Preparation**

The following equipment is recommended for execution of a Formation Integrity Test, for accuracy and control:

- Pumping unit with tanks calibrated in ¼ barrel increments.
- Calibrated gauges covering anticipated pressure ranges mounted on a manifold.
- Chart recorder.

### **10.9.3 Test Procedure**

The following procedure shall be adhered to when performing a Formation Integrity Test:

1. Drill out cement plus 3 m of new formation.
2. Circulate clean to a balanced mud weight (use old mud from previous section).
3. Pull the bit back in casing shoe.
4. Make sure the hole is filled up and close the annular BOP (Hydriil) around the drill pipe.
5. Rig up the pump to the drill pipe. Use a pressure gauge of appropriate range (0 - 1,500 psi.), mounted at the pump unit manifold.
6. Slowly pump mud until pressures begin to increase. Volume pumped will start from this point.
7. Pump 0.125 - 0.25 bbl and wait for 2 minutes or the time required for the pressure to stabilise in the case this takes longer.
8. Record the volume pumped, and the bleed back stabilised pressure.
9. Repeat items 6 & 7 and plot pressures versus cumulative mud volume
10. Continue procedure until either the final stabilised pressure, after the waiting time, deviates from the expected pressure from the plot or the required maximum pressure is reached.
11. Keep well closed in to verify that a constant pressure has indeed been obtained.
12. Release pressure and record volume recovered in tank.

### 10.9.4 Calculations

Formation Intake Gradient (FIG)

$$\text{FIG} = \frac{\text{LOP} + (\text{CSD} \times \text{MG})}{(\text{CSD} - \text{RKBE})} \text{ psi/ft}$$

Effective Mud Gradient (EMG)

$$\text{EMG} = \frac{\text{LOP} + (\text{CSD} \times \text{MG})}{\text{CSD}} \text{ psi/ft}$$

Maximum Allowable Annular Surface Pressure (MAASP)

$$\text{MAASP} = \text{LOP} - (\text{CSD} \times \text{MG}) \text{ psi}$$

Formation Breakdown Pressure (FBP)

$$\text{FBP} = \text{LOP} + (\text{CSD} \times \text{MG})$$

Where:

LOP	=	Leak-Off Pressure (psi), surface pressure recorded during the test
CSD	=	Shoe Depth of last casing set (TVD ft RKB)
MG	=	Mud Gradient (psi/ft)
RKBE	=	Rotary Kelly bushing elevation above ground level (ft)



## APPENDIX 1: GENERAL WELL CONTROL FORMULAE

### 1. The Formation Pressure ( $P_0$ )

$$P_0 = P_{dp} + (D_h \times \rho_1) \text{ psi}$$

$P_0$  = Formation Pressure (psi)

$P_{dp}$  = Shut in drill pipe pressure (psi)

$D_h$  = Depth of hole (ft)

$\rho_1$  = Formation pressure gradient (psi/ft)

### 2. The new mud gradient to balance $P_0$ ( $\rho_2$ )

$$\rho_2 = P_0 \div D_h \text{ psi/ft}$$

### 3. The height of the influx ( $h_{inf}$ )

$$h_{inf} = V_{inf} \div CAP_{ann} \text{ ft}$$

$V_{inf}$  = Volume of influx (bbl)

$CAP_{ann}$  – Annular capacity (bbl/ft)

### 4. The gradient of the influx ( $\rho_{inf}$ )

$$\rho_{inf} = \rho_1 - (P_{ann} - P_{dp}) \div h_{inf} \text{ psi/ft}$$

$P_{ann}$  = Shut in casing pressure (psi)

### 5. Type of influx

$\rho_{inf} < 0.2$  psi/ft is gas

$\rho_{inf} < 0.35 - 0.39$  psi/ft is crude oil

$\rho_{inf} < 0.433$  psi/ft is water

$\rho_{inf} < 0.433 - 0.465$  psi/ft is salt water

### 6. Volumes

#### Contents of string

$$V_{str} = CAP_{dp} \times (D_h - L_{dc}) + CAP_{dc} \times L_{dc} \text{ bbls}$$

$V_{str}$  = Volume of string (bbl)

$CAP_{dp}$  = Capacity of dp (bbl/ft)

$L_{dc}$  = Length drill collars (ft)

$CAP_{dc}$  = Capacity of dc (bbl/ft)

$L_{dc-oh}$  = Length dc in oh (ft)

#### Contents of annulus open hole section

$$V_{dc-oh} = CAP_{dc-oh} \times L_{dc-oh} \text{ bbls}$$

$V_{dc-oh}$  = volume between oh and dc (bbl)

$CAP_{dc-oh}$  = Capacity between dc and oh (bbl/ft)

$$V_{dp-oh} = CAP_{dp-oh} \times L_{dp-oh} \text{ bbls}$$

$V_{dp-oh}$  = volume between oh and dp (bbl)

$CAP_{dp-oh}$  = Capacity between dp and oh (bbl/ft)

#### Contents of annulus casing section

$$V_{csg-dp} = CAP_{csg-dp} \times D_{csg} \text{ bbls}$$

$L_{dp-oh}$  = Length dp in oh (ft)

$V_{csg-dp}$  = volume between csg and dp (bbl)

$CAP_{csg-oh}$  = Capacity between csg and oh (bbl/ft)

$D_{csg}$  = Depth of casing (ft)

### 7. Pre kick calculations

$$1. \text{ MAASP} = (\rho_{fs} - \rho_1) \times D_{csg} \text{ psi}$$

$$2. \text{ CAP}_{str} = 9.7138 \times \phi_{id\ pipe}^2 \times 10^{-4} \text{ bbls/ft}$$

**Note:** 1)  $\phi_{id\ pipe}$  in inches. 2)  $\text{CAP}_{str} = \text{CAP}_{dp} + \text{CAP}_{dc} + \text{etc.}$

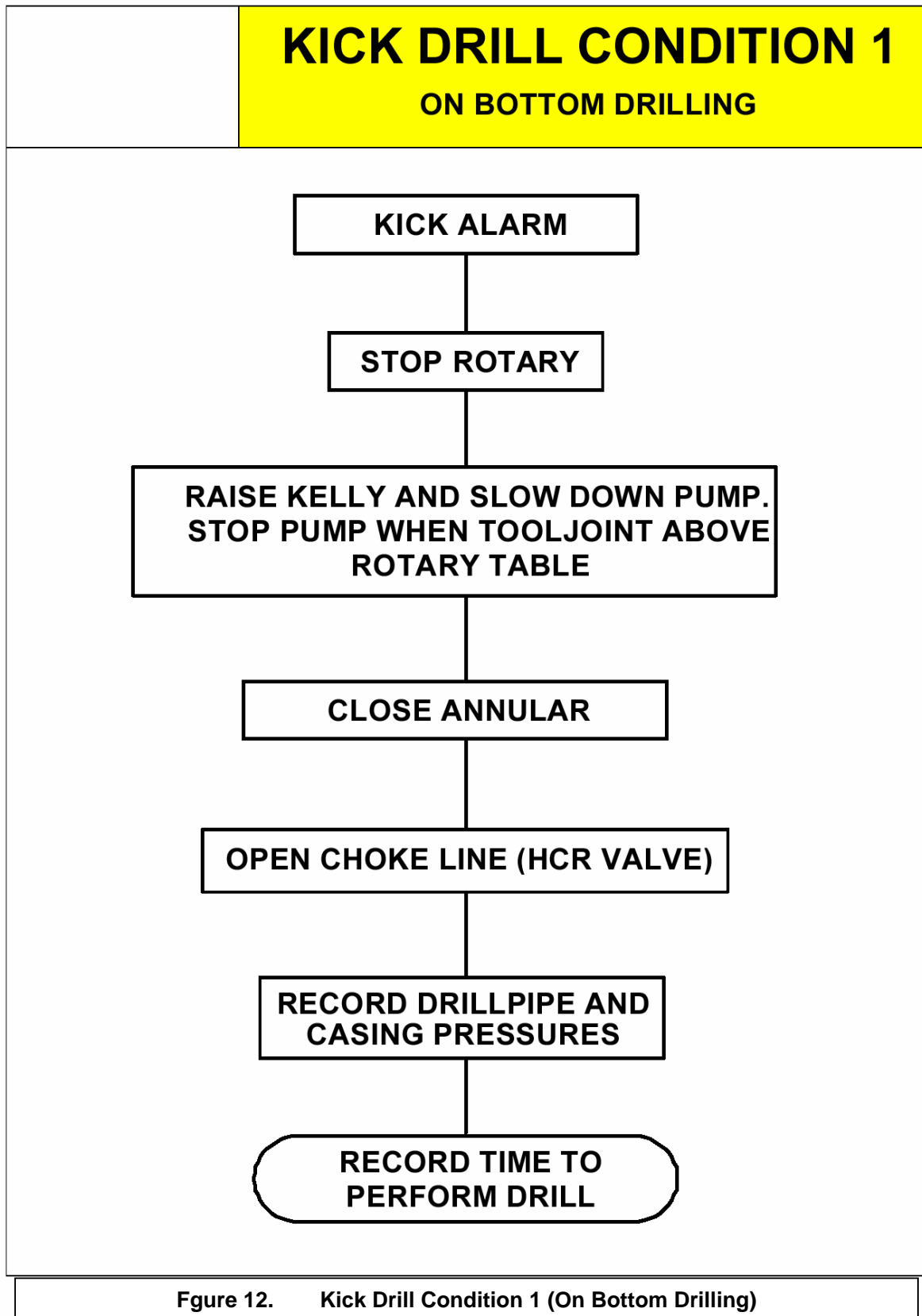
$$3. \text{ CAP}_{ann} = 9.7138 \times (\phi_{id\ hole}^2 - \phi_{id\ pipe}^2) \times 10^{-4} \text{ bbls/ft}$$

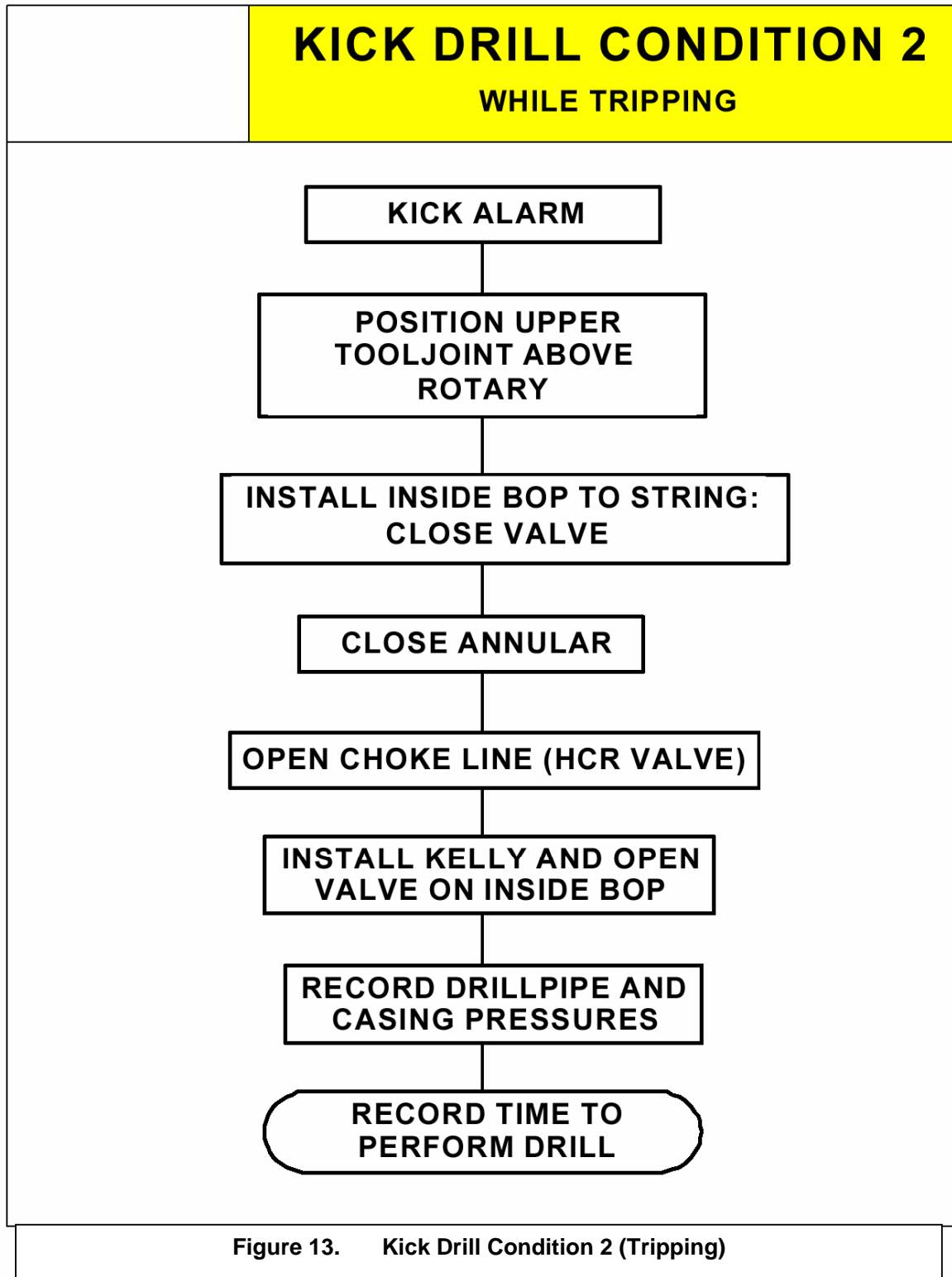
**Note:** 1)  $\phi$  in inches 2)  $\text{CAP}_{ann} = \text{CAP}_{dc-oh} + \text{CAP}_{dp-oh} + \text{CAP}_{dp-csg} + \text{etc.}$

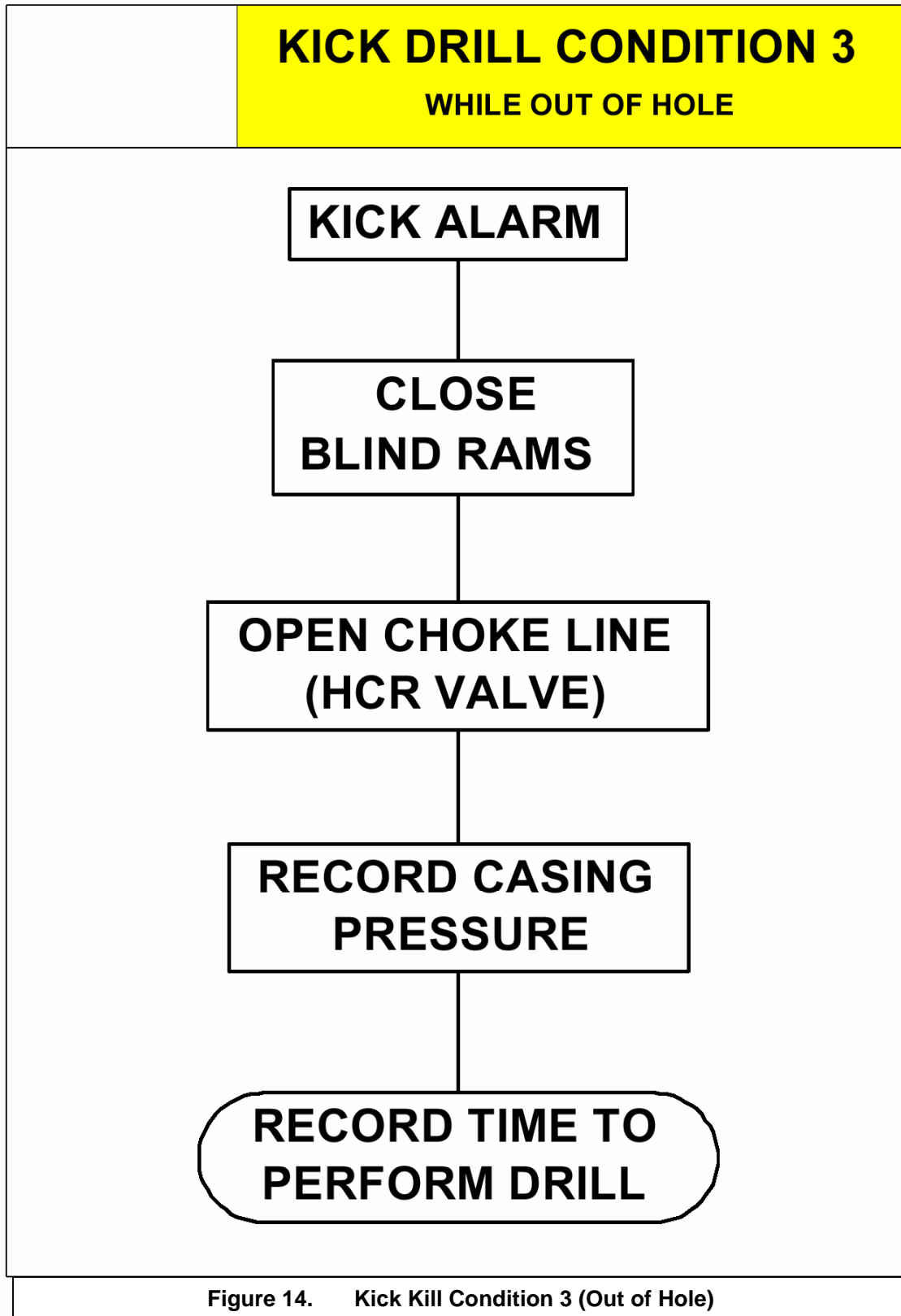
## Appendix II: Well Control Schematic Procedures

This Chapter contains the following schematic representations of the key well control procedures described in this Manual:

<u>Schematic</u>	<u>Page</u>
• Kick Drill Condition 1 (on Bottom Drilling)	34
• Kick Drill Condition 2 (Tripping)	35
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• Shut In Procedure (While Drill Collars Are Adjacent To Preventers)	40
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## KICK DRILL CONDITION 4 WHILE DRILL COLLARS ARE ADJACENT TO PREVENTERS

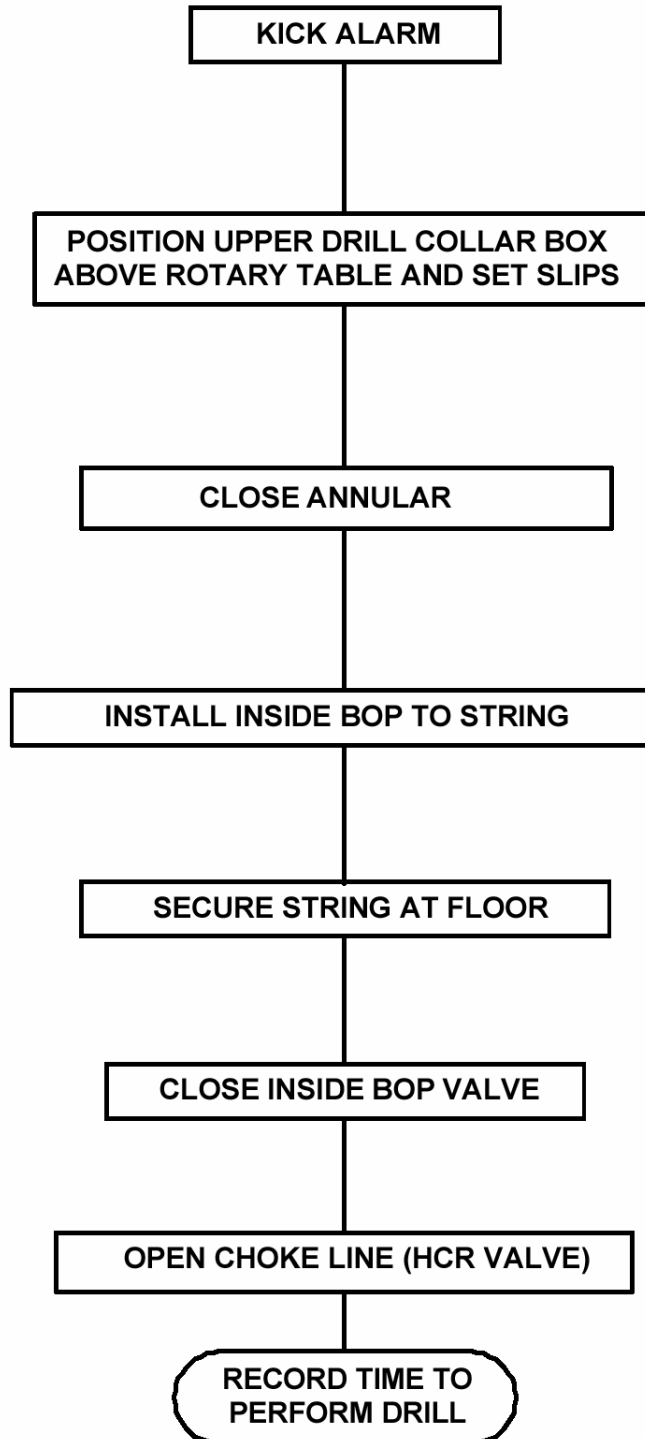
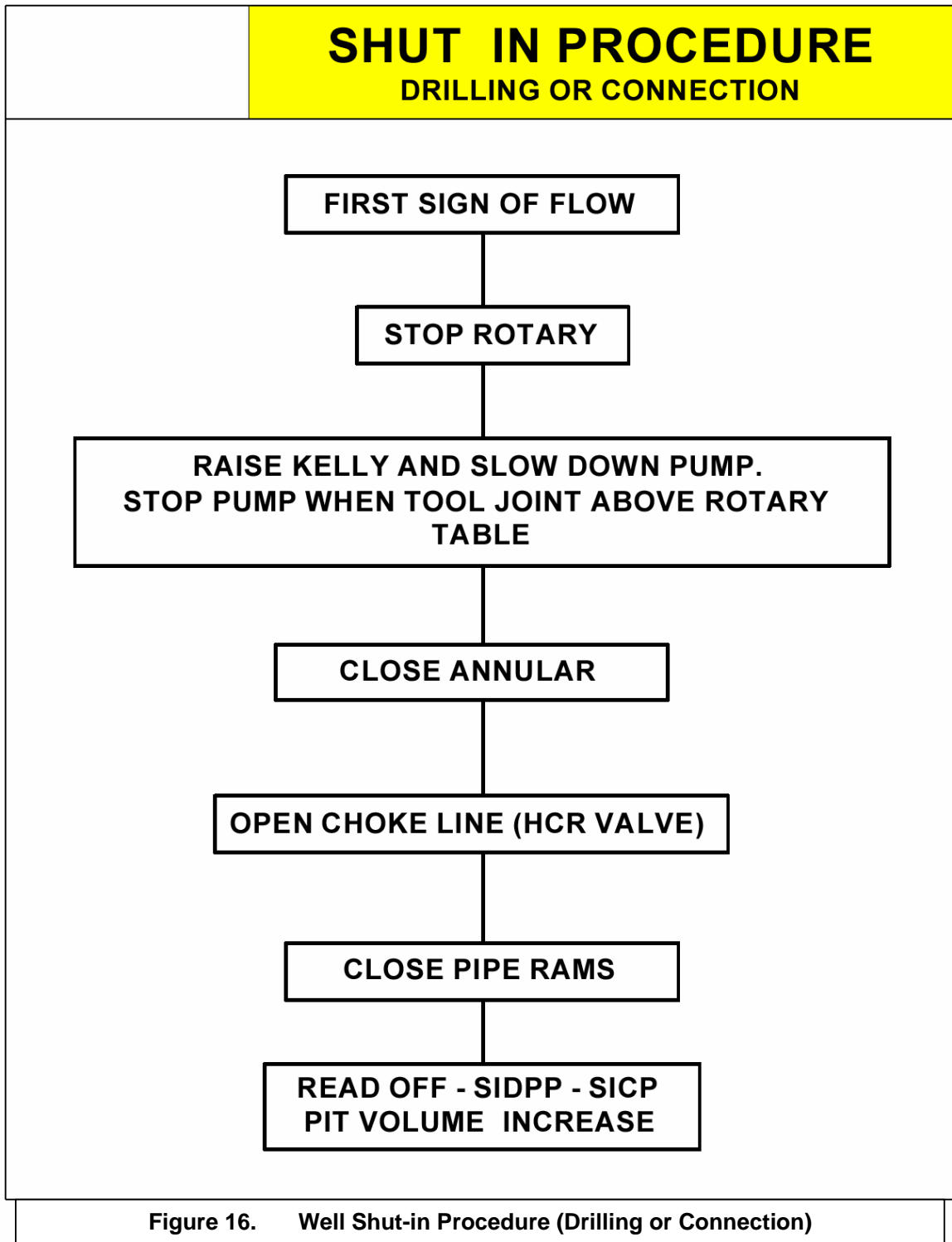
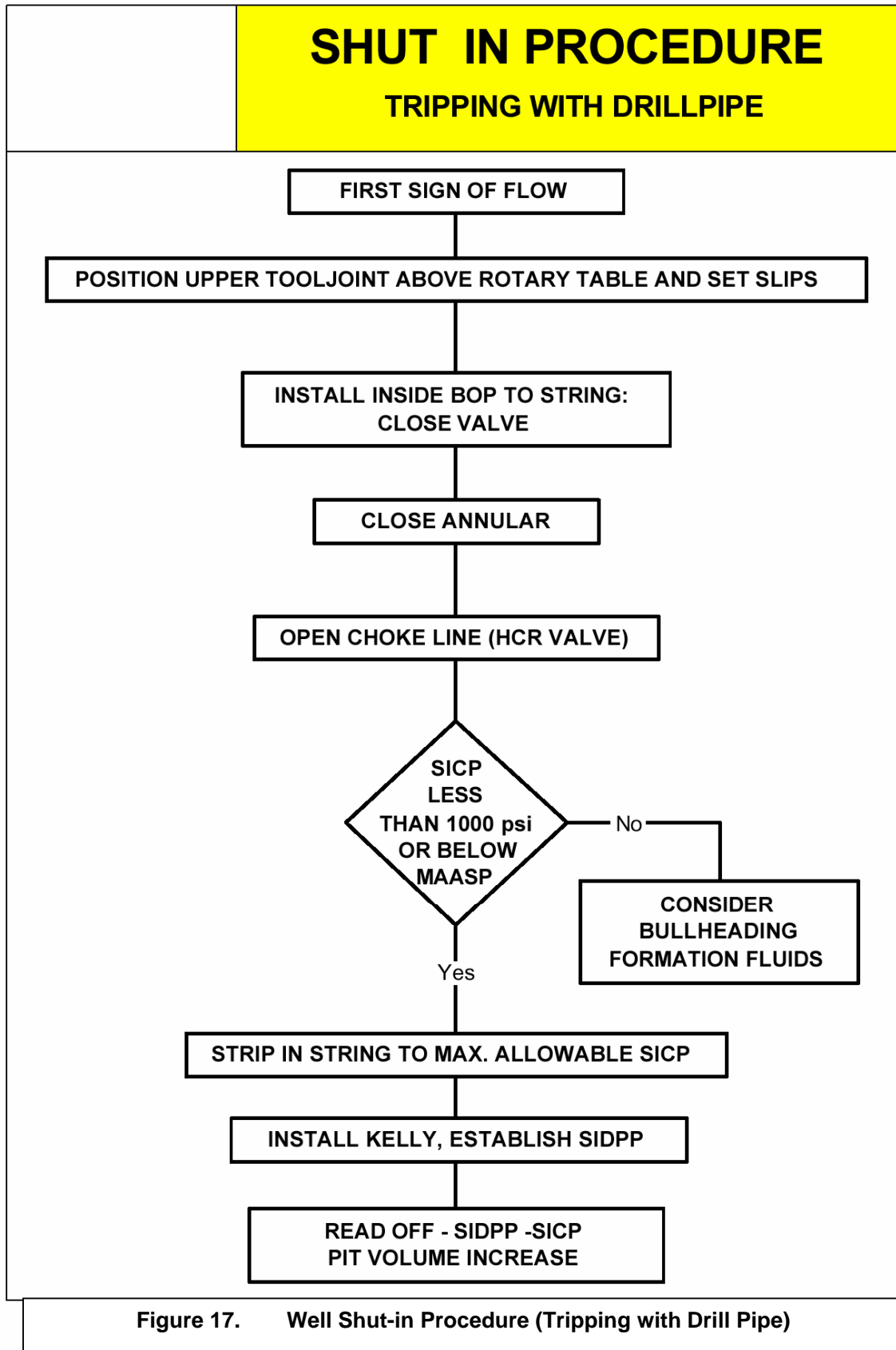


Figure 15. Kick Drill Condition 4 (Drill Collars Adjacent to Preventors)







## SHUT IN PROCEDURE WHILE DRILL COLLARS ARE ADJACENT TO PREVENTERS

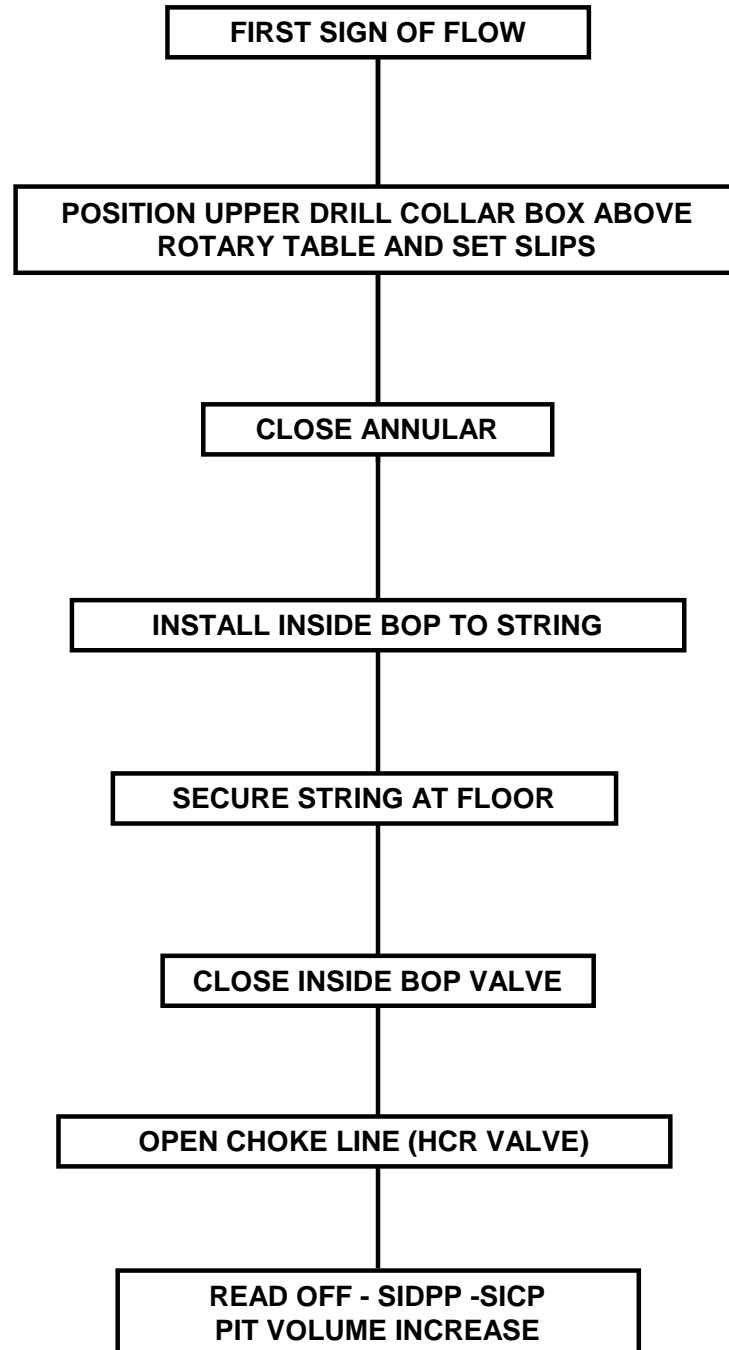


Figure 18. Well Shut-in Procedure (Drill Collars Adjacent to Preventors)

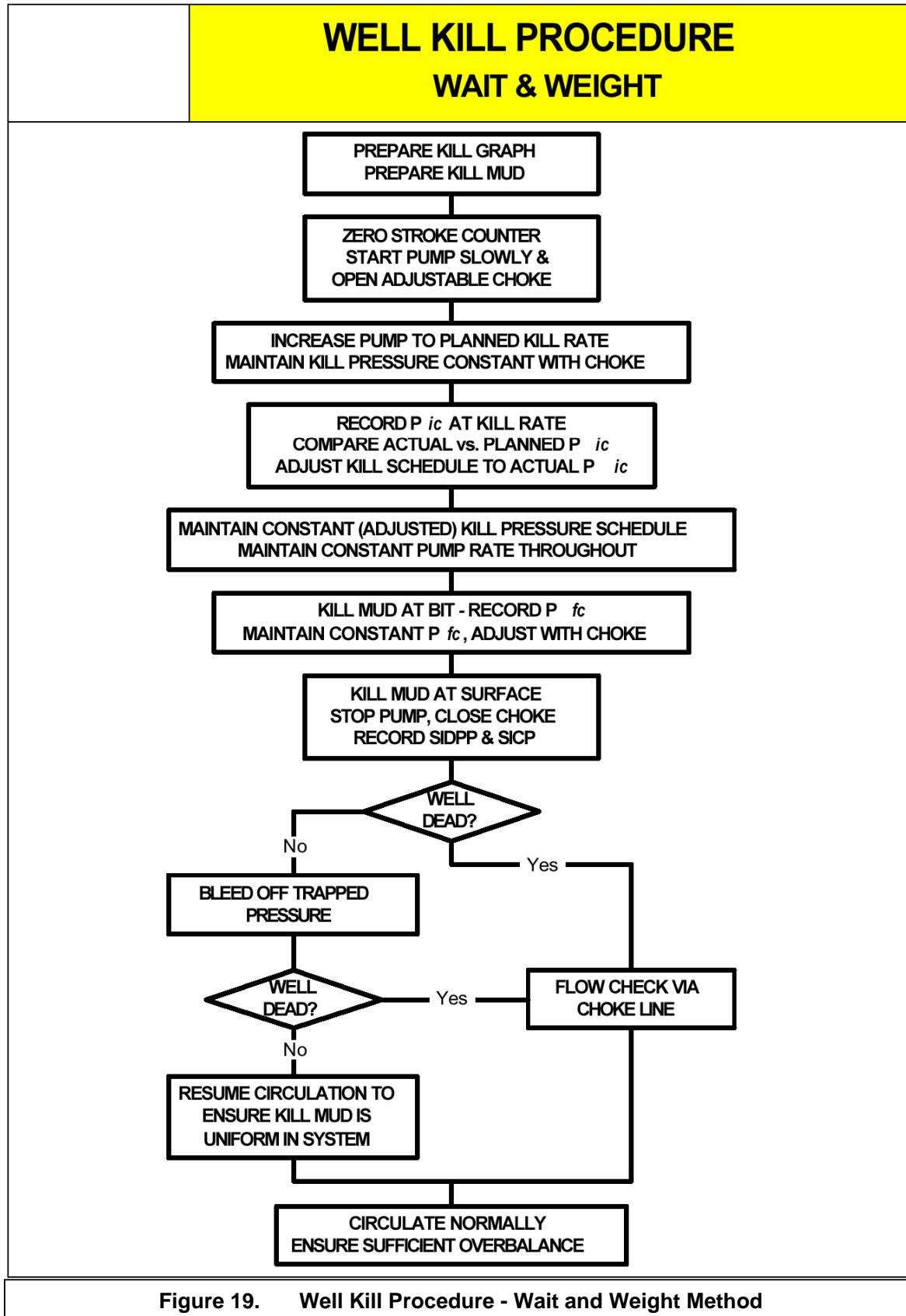
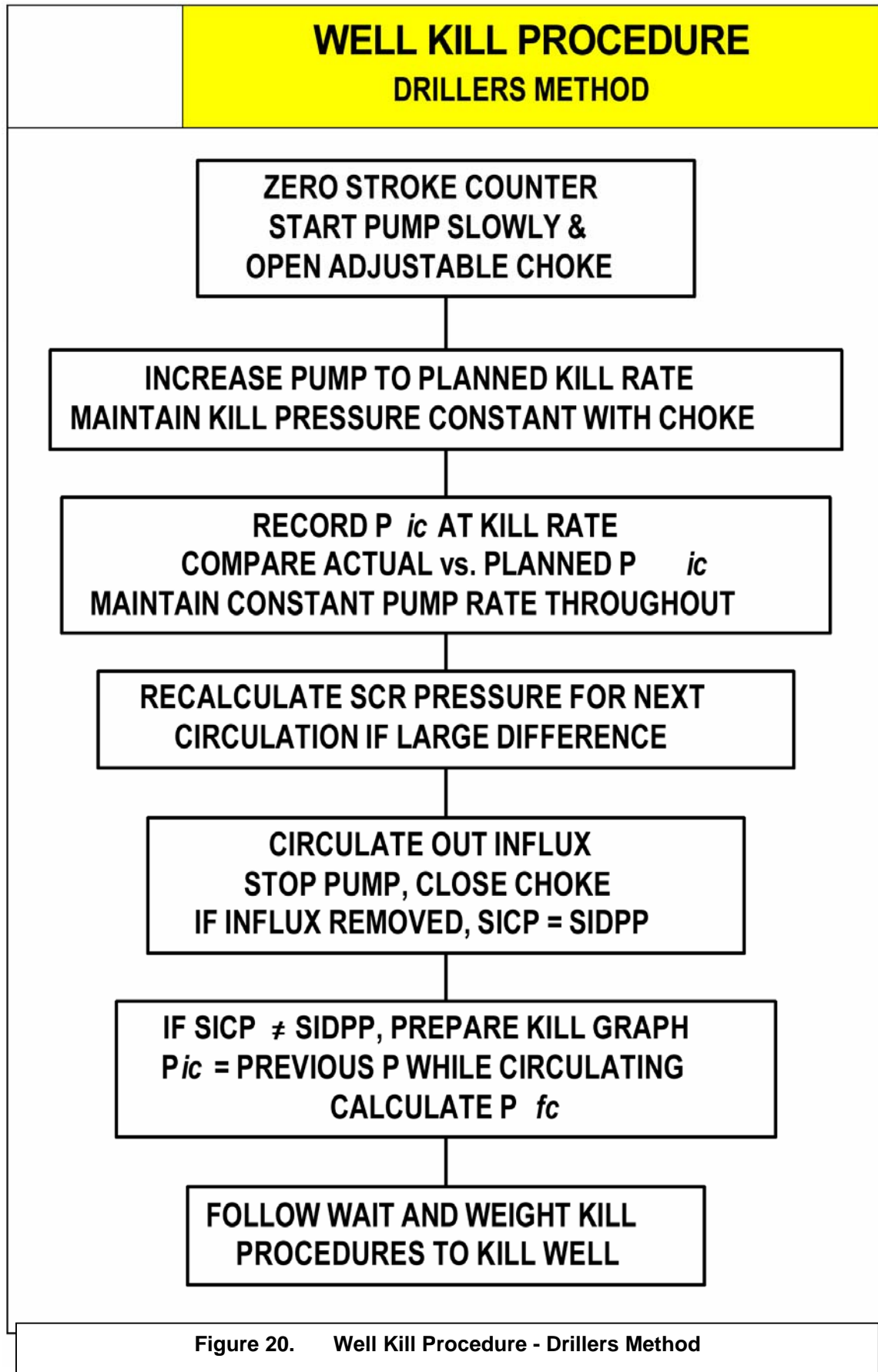
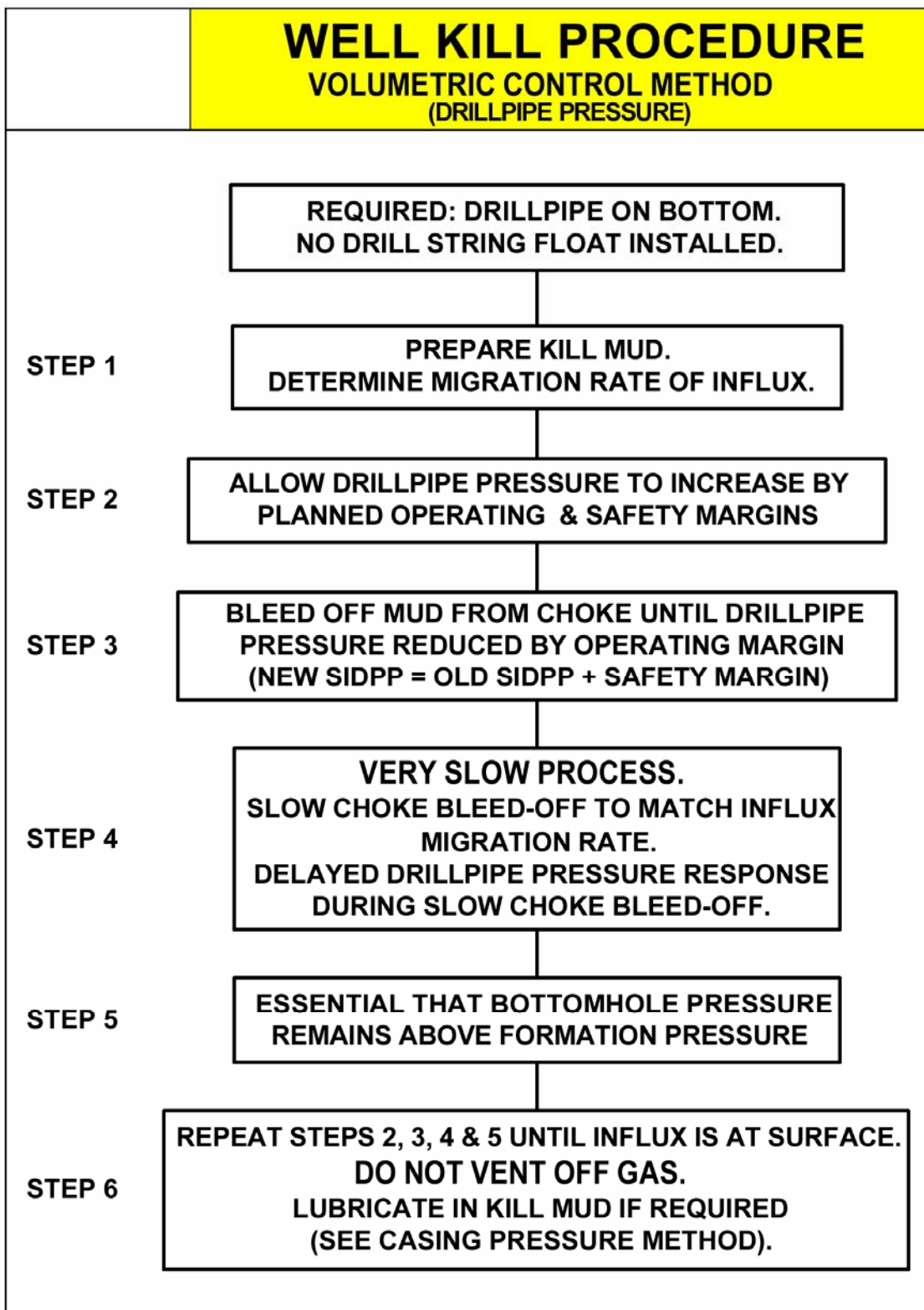
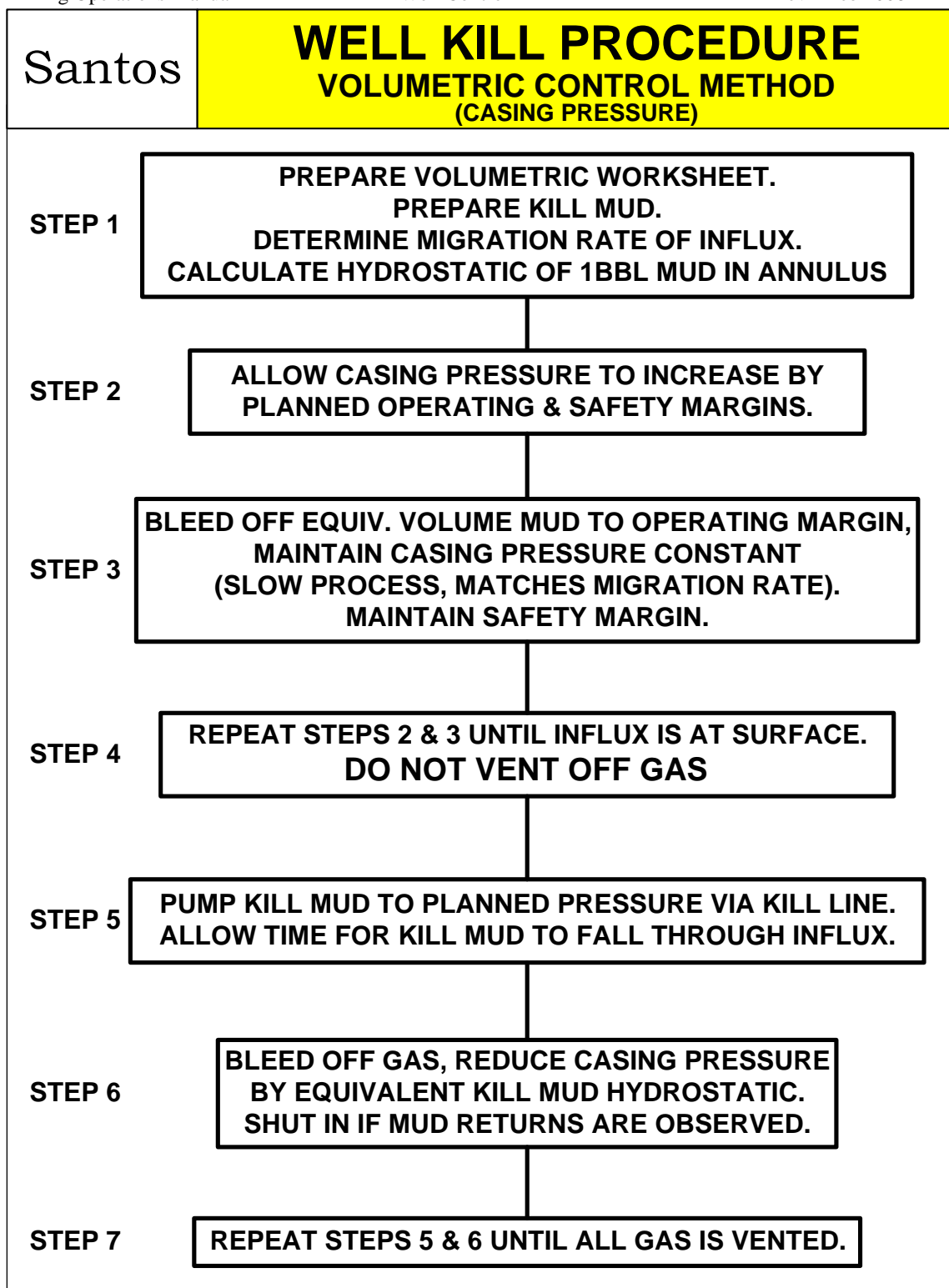


Figure 19. Well Kill Procedure - Wait and Weight Method

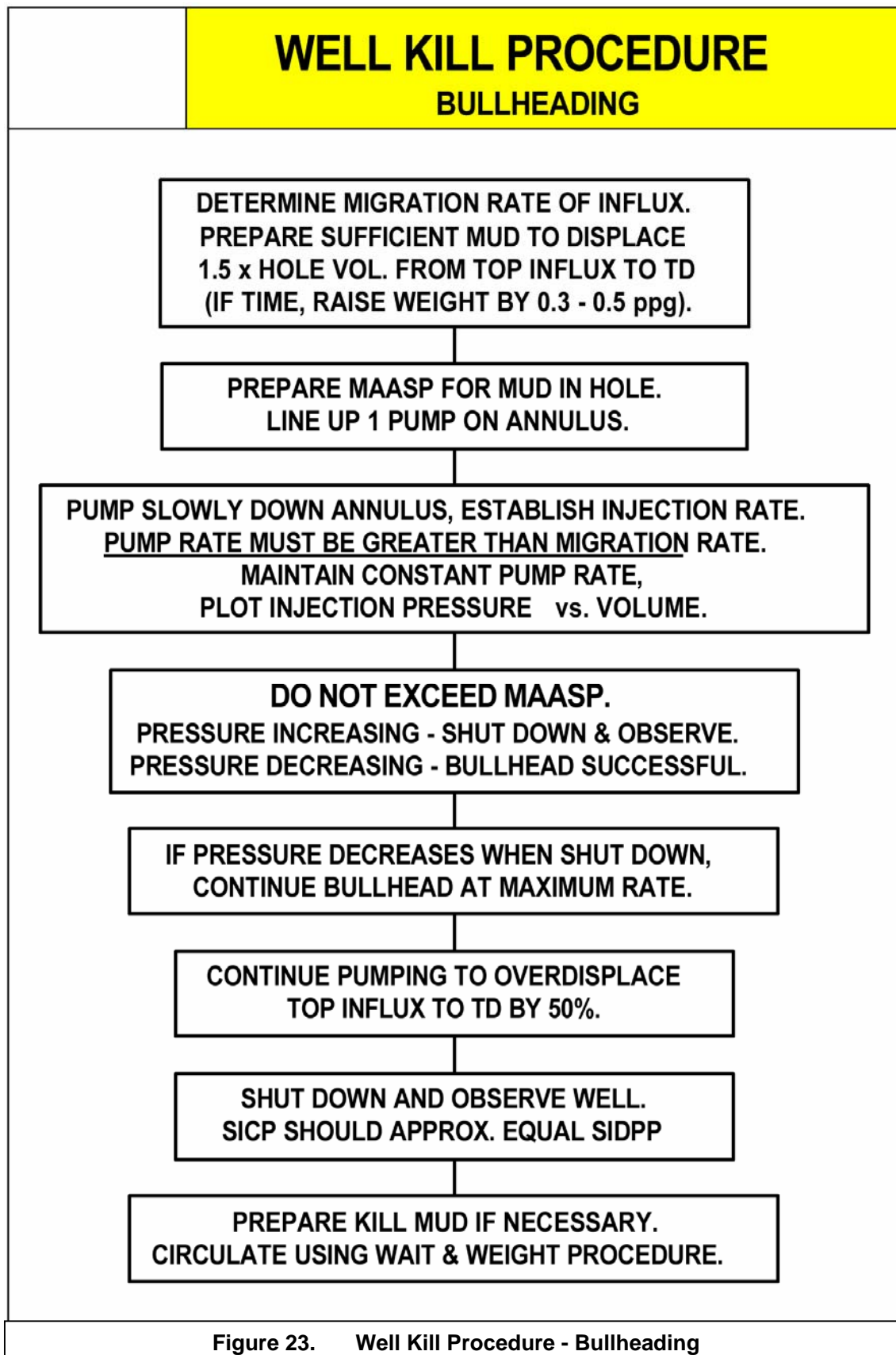




*Well Control Procedure - Volumetric Control Method (Drill pipe pressure)*



**Figure 21. Well Kill Procedure – Volumetric Control Method (Casing Pressure)**



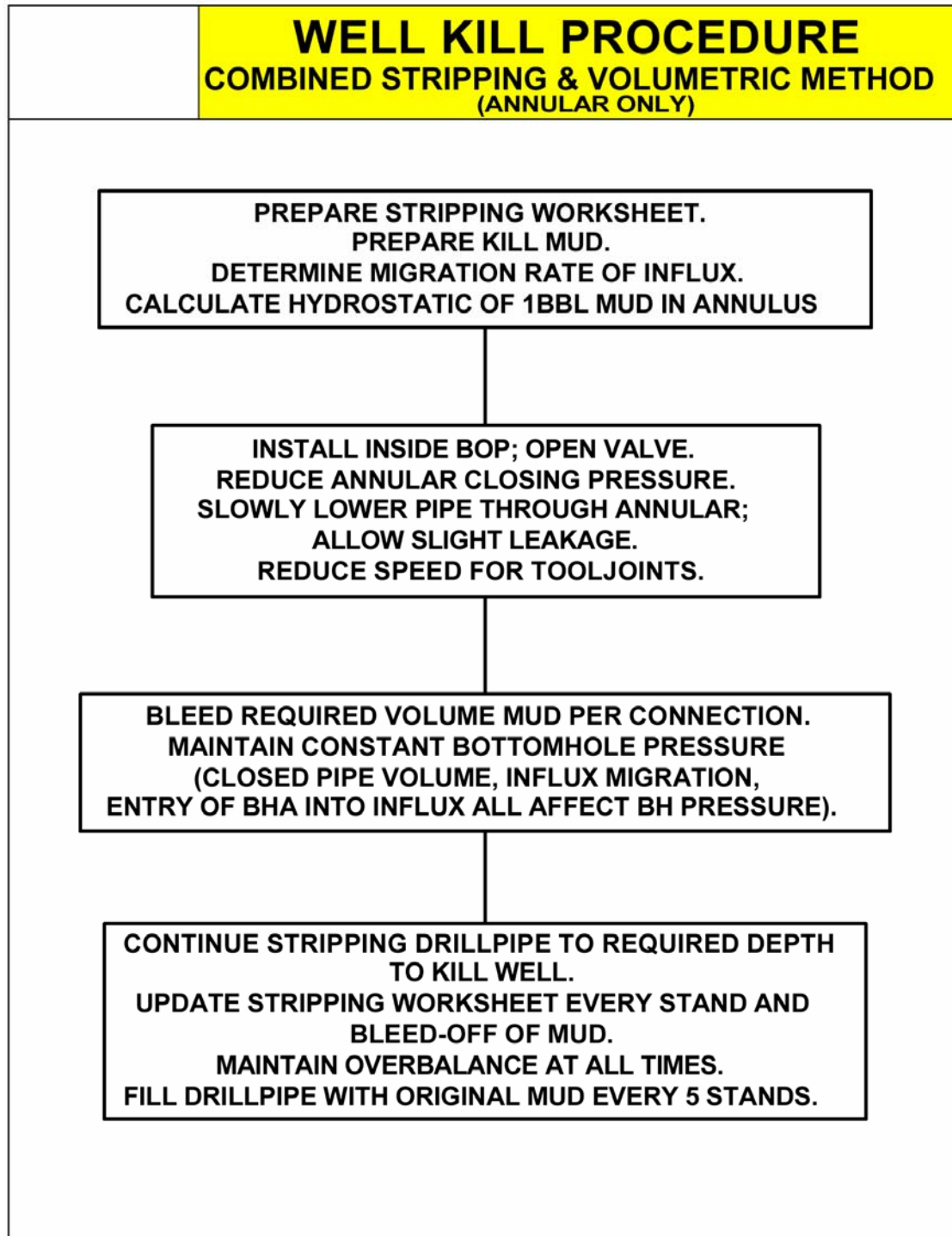


Figure 24. Well Kill Procedure – Combined Stripping & Volumetric Method (Annular only)

## **Appendix III: Minimum Pressure Control Equipment Standards**

### **General BOP Arrangement**

All pressure contained components of the BOP stack and related equipment shall be constructed of material that meets the standards of NACE MR-01-75 and API RP-53.

Welded, flanged, or hub connections are mandatory on all pressure systems above 2000 psi (as opposed to threaded connections).

BOP stacks should comprise at least:

1. One annular preventer.
2. One double, or two single hydraulic operated ram type preventers; one of which must be equipped with correct size pipe rams, the other with blind rams. Locking mechanisms (integral or mechanical) are required for these preventers.
3. One full opening drilling spool with two 3" bore (min) side outlets.

A single 10 gallon surge bottle will be placed near the annular preventer on the close port of the hydraulic lines.

### **Choke And Kill System**

The choke and kill system shall provide the valves and piping required to allow controlled circulation of the well under pressure. The assembly, connections, full opening gate valves, fittings, piping, etc., subject to well or pump pressure should be flanged, clamped or welded and have a rated working pressure at least equal to the rated working pressure of the BOP. The choke and kill system shall include:

A double valve arrangement on every line/outlet of the BOP.

A hydraulically operated (HCR) valve included in the double valve arrangement on the choke line.

Lines connecting the BOP stack to the choke manifold.

A choke manifold.

A flare line connected to the choke manifold.

### **Choke and Kill Lines**

Dedicated kill lines must not be smaller than 2" nominal and shall be fitted with two gate valves and a non-return valve. Choke lines must not be smaller than 3" through bore and are to be connected with two valves to the BOP stack of which the outer valve shall be hydraulically operated (ie HCR).

Choke lines shall be as straight as practicable and firmly anchored to prevent excessive whip or vibration. Turns, if required, should be targeted. Excessive bends in piping or 'Co-Flexip' spec hoses is not acceptable. A 'Co-Flexip' spec hose is acceptable in "straight short runs only". The hose must be placed between the hydraulic controlled valve and the flow line leading to the choke manifold.

The distance between anchoring points shall be 4 m (12 ft) or less.

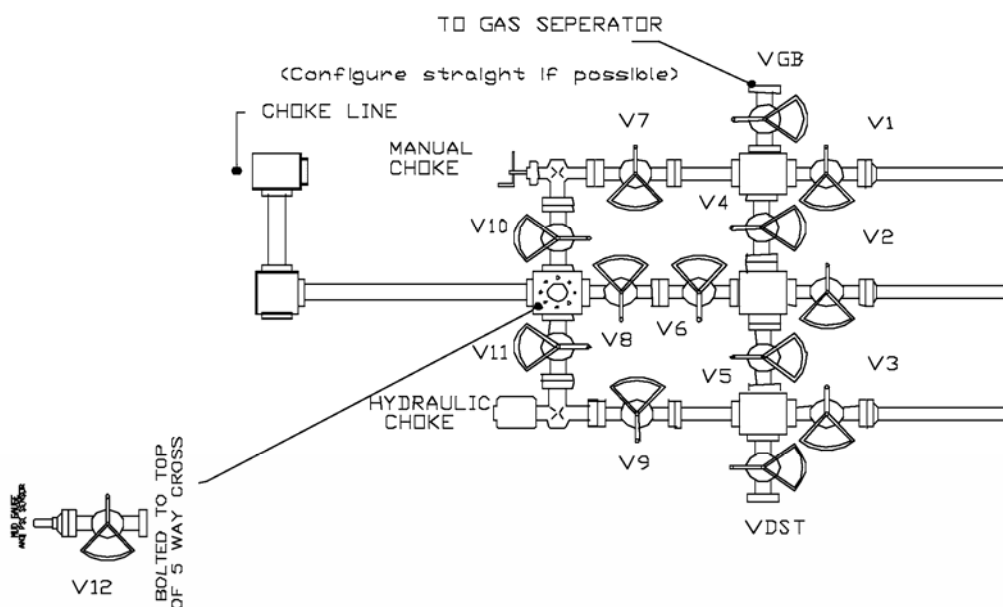
Threaded connections and hammer unions are unacceptable in any section of the line.



## Choke Manifold

The following recommended practices for the installation of a choke manifold shall be adhered to, as specified in API RP53 "API Recommended Practices for Blowout Prevention Systems":

- a) All components should be selected in accordance with applicable API Specifications, taking into consideration pressures, volumes, temperatures and conditions under which they may be operated (i.e. gas, oil, drilling fluid, hydrogen sulphide, the environment, etc.).
- b) All choke lines shall be 3" nominal diameter or larger, have a minimum number of turns and be securely anchored.



**Figure 25. Minimum Choke Manifold Arrangement**

- c) Only right angle block turns shall be used in the choke manifold and discharge piping.
- d) A 3" nominal internal diameter inlet (or larger) shall be provided into a block five way cross. The through bore of the cross will be 3" diameter (or larger) and the right angle flow paths shall be 3" diameter (or larger).
- e) Outboard of the right angle flow path gate valves, will be one two inch, remotely operated hydraulic choke and one two inch, manually operated choke.
- f) A pressure gauge and a remote sensor measuring the inlet pressure to the manifold shall be provided.
- g) A remote choke control station shall be provided for the remotely operated choke, and must include all monitors necessary to furnish an overview of the well control situation. This includes standpipe pressure, casing pressure and pump strokes. Rig air systems must be of adequate capacity to provide the necessary pressure and volume requirements for control of hydraulically or pneumatically operated chokes and valves. A redundant automatic choke control system, which may be manually operated, should be provided in the event that rig air becomes unavailable.

- h) Baffle chambers not permitted – see Figure 25.
- i) The flare line downstream of the choke manifold shall be 45 m (150") in length, with a minimum internal diameter of 2.7" (ie 3 ½" tubing).  
In addition, chokes should incorporate a suitable bleeder valve facility to ensure that the pressure can be released prior to removal of the bonnet nut. Hammer type threaded bonnet nuts are not recommended. Flanged or bonnet clamp connections are preferred

### **Mud-Gas Separator**

The unit vessel shall have a minimum inside diameter of 1.2 m (48") and be at least six metres (twenty feet) in length.

The top and bottom sections of the vessel shall be curved or dome topped. No flat top or bottom is acceptable. The vessel shall withstand a static pressure test of 600 psi when manufactured. Vessel will not be required to be pressure tested at regular intervals.

The mud gas separator shall be installed with a minimum 8" vent line, a minimum 4" choke manifold discharge line, and a mud seal of at least 1.5 m (5 ft) The mud gas separator discharge line (and the choke manifold discharge line) shall under no circumstances, be connected to the vacuum degasser inlet.

The following shall be met when configuring the pipework for the mud/gas separator;

- there are to be no valves, pipe expansion or contractions within 3 m (10 ft) of the inlet nozzle.
- if a bend is required in the feed pipe it shall be in a vertical plane through the axis of the feed nozzle.
- the gas outlet line reducer should be no nearer to the top of the vessel than 0.6 m (2 ft).

The mud-gas separator shall have the vent lines (8" min) leading to the flare pit (ie approx. 150' from well centre) and be manufactured from Schedule 40 (or higher) rated pipe. Low places in the vent lines should be avoided in order to prevent liquids being trapped in them.

The mud discharge line of the separator must be at least 6" in diameter and of similar pressure rating of the vessel.

A dump outlet shall be constructed at the base of the vessel and equipped with a full open valve consistent with the pressure rating of the vessel.

### **Vacuum Degasser**

A vacuum degasser is required on all rigs. Degasser systems shall be positioned on the intermediate section of the active pits, the discharge may be allowed to flow into the suction pit. The flow capacity of this degasser must be at least equal to the maximum drilling flow rate expected in production hole (500 gallons per minute). A centrifugal type degasser is acceptable.

### **BOP Control Systems**

Control systems for surface BOP stacks shall consist of the following:

- One independent automatic accumulator unit rated for 3000 psi WP with a control manifold, clearly showing 'open' and 'closed' positions for preventers and the hydraulic operated choke line valve. It is essential that the BOP operating unit be equipped with 0-3000 psi regulator valves similar to the Koomey type TR-5 which will not 'fail open', causing complete loss of operating pressure.

The system will be supported by two independent hydraulic power sources. These sources can be powered by rig air or electric powered pumps. These pumps will be rigged to automatically recharge the unit as the pressure in the accumulator bottles drops. Accumulator charging pump output shall be capable of charging the accumulator system from precharge pressure to operating pressure in 15 minutes or less.

The unit shall be located in a safe area away from the drilling floor. It shall include a low pressure warning alarm and hydraulic fluid level indicator or low fluid level warning alarm.

- All BOP stack installations should have at least one graphic remote control panel showing 'open' and 'closed' positions for each preventer and the pressure operated choke line valves. This panel must include a master shut-off valve and controls for regulator valves and for a bypass valve. The panel must be located near the driller's position. If the accumulator unit is not located in a safe area, a second remote panel must be available (in a safe area).
- High pressure fire-resistant control hoses with a working pressure of 3000 psi are preferred, although steel swivel joints are acceptable. The hoses should be steel wrapped (co-flex type) to provide greater resistance to fire and improved durability.

#### **Accumulator Requirements**

With an initial precharge of 1000 psi, the accumulator volume should be sized to keep at least 1200 psi on the unit (with pumps inoperative) after:

- Closing all functions
- Opening all functions
- Closing the annular
- Opening the remote operated valve

Closing systems of BOP's shall be capable of closing each ram preventer within 30 seconds; the closing time should not exceed 30 seconds for annular preventers smaller than 20".

#### **Drillstring BOP Valves**

Components for shutting in the drillpipe internally are a basic part of well control equipment. All drill string BOP valves must have a pressure rating equal to, or greater than, the BOP stack.

The following drill string BOP valves (with connections and/or cross-overs to suit the drill pipe and collars in use) shall be available on the drill floor and ready for immediate use at all times:

- A full bore Kelly Cock shall be installed at the base of the kelly.
- A ball type stabbing valve (lower kellycock), together with an operating handle for the valve, and removable handles for easy stabbing.
- A rotating type circulating head
- Inside BOP (Gray type or equivalent).

The outside diameter of the tools will be similar to the tool joint outside diameters to facilitate stripping operations.

A test sub for testing the kelly and kelly cocks shall be available on the rig.

### **Kick Detection And Well Monitoring Equipment**

An indicating and recording mud pit level system, capable of providing early visual and audible warning of gain or loss of fluid in the well, shall be installed in those mud tanks which serve as active mud tanks. This system must be able to detect and allow shut in response by the Driller for a maximum loss/gain of 5 barrels.

The complete system must be kept in proper working condition at all times. An indicator or recording chart must be easily visible to the driller.

Other minimum requirements are below:

- a) The following minimum kick detection equipment shall be available and fully operational:
  - Flowline monitor
  - Trip tank complete with a mechanically operated indicator of the trip tank level visible from the Driller's position. This system must be able to detect and allow a shut in response by the Driller for a maximum loss/gain of 1 barrels
- b) Continuous monitoring and recording of the following parameters:
  - Weight on bit and hook load
  - Standpipe pressure and choke pressure
  - Rate of penetration
  - Mud pump rate(SPM)

## **CHAPTER 11 SUSPENSION AND ABANDONMENT**

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## 11.1 OBJECTIVES

The Drilling Department shall produce “fit for purpose” suspension or abandonment designs in accordance with the standards and procedures detailed in this chapter and relevant statutory requirements and regulatory standards. The suspension and/or abandonment section of the Drilling Program shall ensure that:

- The final well status meets all relevant statutory requirements regarding zonal isolation.
- Primary well control is in place and shall not deteriorate with time.
- Cement plugs are set and tested with a minimum of delay.

The DSV shall ensure that the requirements for the suspension or abandonment detailed in the program are carried out by the Drilling Contractor in accordance with the standards and procedures contained in the following sections.

## 11.2 RESPONSIBILITIES

Responsibilities for the implementation, supervision and verification of suspension, abandonment and lease clean-up operations are tabulated below.

Task	Performed by	Verified by
Prepare suspension / abandonment programme (part of Drilling Programme)	DM	DM
Submit Suspension or Abandonment programme to regulatory authority for approval	DM	DM
Identify formation tops.	Mud Loggers / WGL	DSV
Execute the Suspension or Abandonment Programme	Drilling Contractor	DSV
Verify integrity of the plugs as specified	Drilling Contractor	DSV
Prepare Reports (Form F-331 and Form F-332) with diagrams	DSV	DM
Execute initial lease clean-up	Drilling Contractor	DSV

**Table 66. Responsibilities for Suspension, Abandonment and Lease Clean-up**

### **11.3 STANDARDS AND GUIDELINES**

The GSLM standards for the suspension or abandonment of wells are outlined in this Chapter.

All wells that are permanently suspended or abandoned must be left in a condition that prevents the potential leakage of formation fluid to surface.

#### **11.3.1 Well Suspension**

The following standards shall apply to the long term suspension of wells:

1. To protect against ingress of wellbore pressure into the production casing, the well shall have, as a minimum, two lines of defence present of which at least one has been tested. These may include:

- The Casing string
- Cement filled shoe track
- Mechanical Plug
- Kill weight fluid

Kill weight mud/brine can only be considered a line of defence if its weight is known and it has been tested to above leak-off to ensure there are no losses. The settling of weighting elements shall also be considered.

2. Suspended wells which have open perforations shall have all perforations isolated by a bridge plug and a cement plug depending upon the well requirements.

### **11.3.2 Well Abandonment**

#### **General Standard**

Each well is to be evaluated individually to design the abandonment program. Abandonment of wells or sections of wells shall be conducted in such a manner that reservoir management is not compromised, hydrocarbons are prevented from migrating to surface or between zones of differing pressure regimes, and the well location is restored to its original condition or to an agreed condition. All potable water bearing, saline water bearing or hydrocarbon bearing permeable zones shall be effectively isolated from one another.

#### **Potable Water Supplies**

It is a statutory requirement that any saline water sands shall be isolated from fresh water sands in order to prevent contamination of artesian potable water supplies.

#### **Hydrocarbon Zones**

It is a statutory requirement that isolation procedures shall prevent commingling of any hydrocarbon or water producing zones.

#### **Isolation Of Open Hole**

- The open hole shall be isolated by placing a series of cement plugs (each a minimum of 50 m ) to extend 25 m below into another permeable section if present, and 25 m above the top of the permeable/hydrocarbon zones (Refer to 8.10.2 for plug setting procedures).
- Only the cement plug set across the casing shoe needs to be pressure tested (LO plus 100 psi ).
- Excess cement shall be 10% over caliper or 20% on theoretical volume if no caliper is available.
- In the absence of permeable/hydrocarbon zones the open hole shall be isolated by placing a cement plug across the previous casing shoe to extend a minimum of 25 m below and 25 m above the casing shoe.
- When lost circulation is anticipated, a mechanical isolation device should be set prior to setting the cement plug.

#### **Isolation Of Hole With Stuck Pipe**

- Provided that no permeable / hydrocarbon zones with cross flow potential are exposed in the stuck pipe section, the fish shall be isolated by cement plug(s) placed on top of the fish.
- In the event permeable zones do exist, attempts shall be made to isolate the annulus between the fish and the hole.

#### **Abandonment of Casing Stubs**

Casing stubs shall be isolated by a cement plug designed to extend a minimum of 25 m below the stub to a point 25 m above the stub. Alternatively a bridge plug can be set 15 m into the stub. In either case plugs must be located ( tagged ) and weight tested as a minimum and 25 m of cement plug set on top of a bridge plug.

#### **Surface Cement Plugs**

A surface cement plug of at least 15 m shall be placed in the smallest diameter casing string exposed at surface.



## 11.4 WELL SUSPENSION

The following standards shall apply to the long term suspension of wells:

- The well shall have a minimum two lines of defence present, of which at least one shall have been tested. These barriers may include:

Casing	Annulus
Cement filled shoe track	Cement filled annulus
Mechanical Plug	Annulus seal
Hydrostatic Head of kill weight fluid	Hydrostatic Head of kill weight fluid
The Casing string	

Kill weight mud / brine can be considered a barrier, provided that its weight is known and it has been tested to above leak-off to ensure that there are no losses. The settling of weighting materials in the fluid shall also be assessed in determining the effectiveness of the fluid as a barrier over an extended period.

- All open perforations in suspended wells shall be isolated by a bridge plug and a cement plug (except where completion's have been run).
- If production casing is run, the well shall be suspended by installing an appropriate tubing spool.
- The wellhead or tubing spool shall be sealed by the installation of a blind flange or X-mas tree.

### 11.4.2 Procedures

If a well is to be temporarily suspended, the outline procedure below shall be followed:

- Cement casing with top of lead cement a minimum of 150 m above the top of the previous casing shoe and the top of the tail cement 65 m above the uppermost hydrocarbon reservoir.
- Pressure test the casing ( as per the program ).
- Install tubing spool and companion flange (DO NOT energise the X-bushing at this stage).
- Grease and cap off ring groove.

### 11.4.3 Minimum Mechanical Barrier Summary

The following minimum mechanical barriers are required prior to nipping down the BOP.

Borehole Location	Barrier
Annulus	1. Casing pack-off (slip and seal assembly / Tubing hanger). 2. Cement 150 m above the previous casing shoe
Wellbore	1. Wellhead 2. Kill weight fluid, and/or 3. Shoe track cement

**Table 67. Minimum Mechanical Barriers - Suspension**

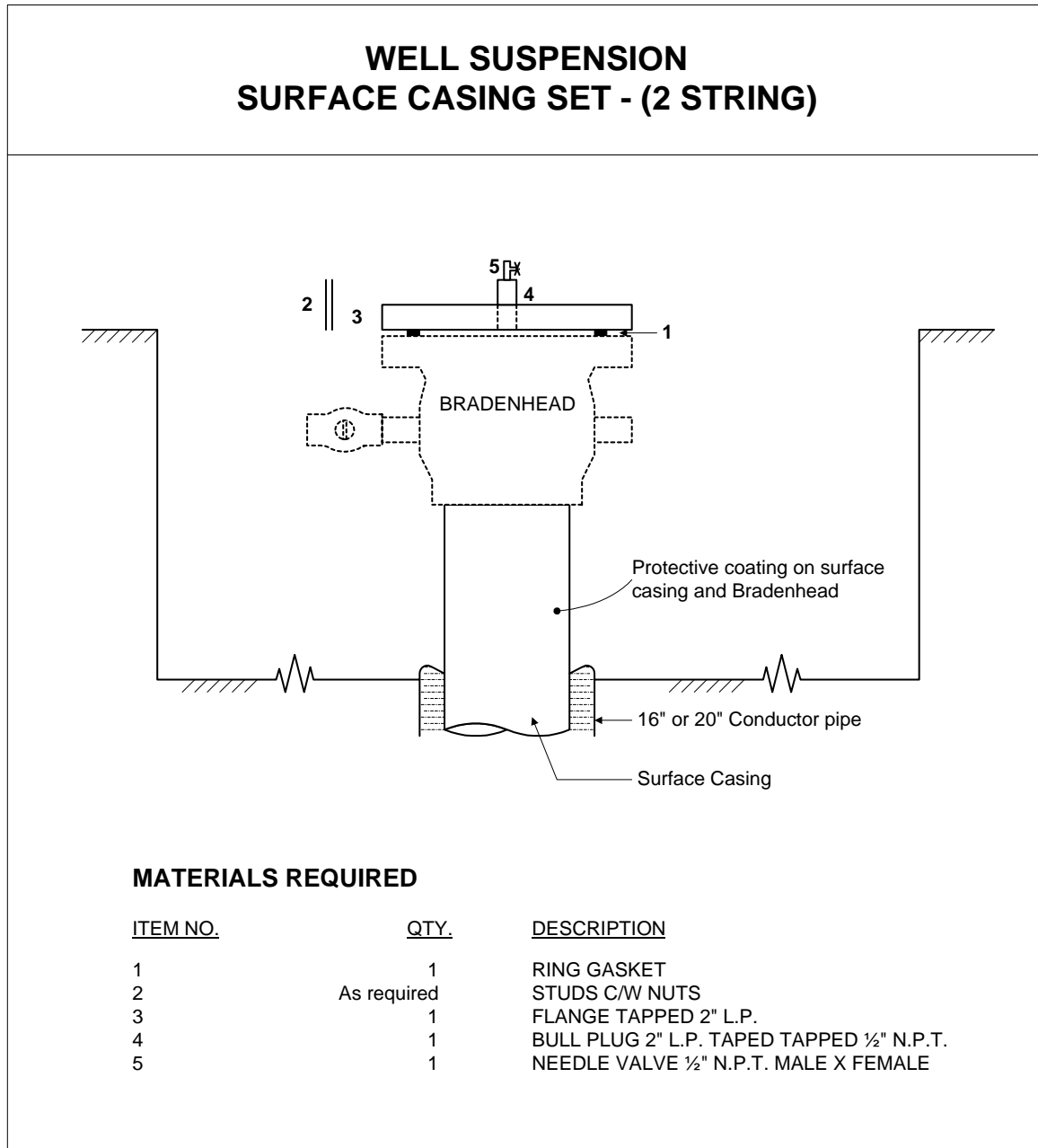
### 11.4.4 Reporting

Upon completion of the suspension operations the DSV shall prepare the Wellhead Installation Report.

### 11.4.5 Suspension Schematics

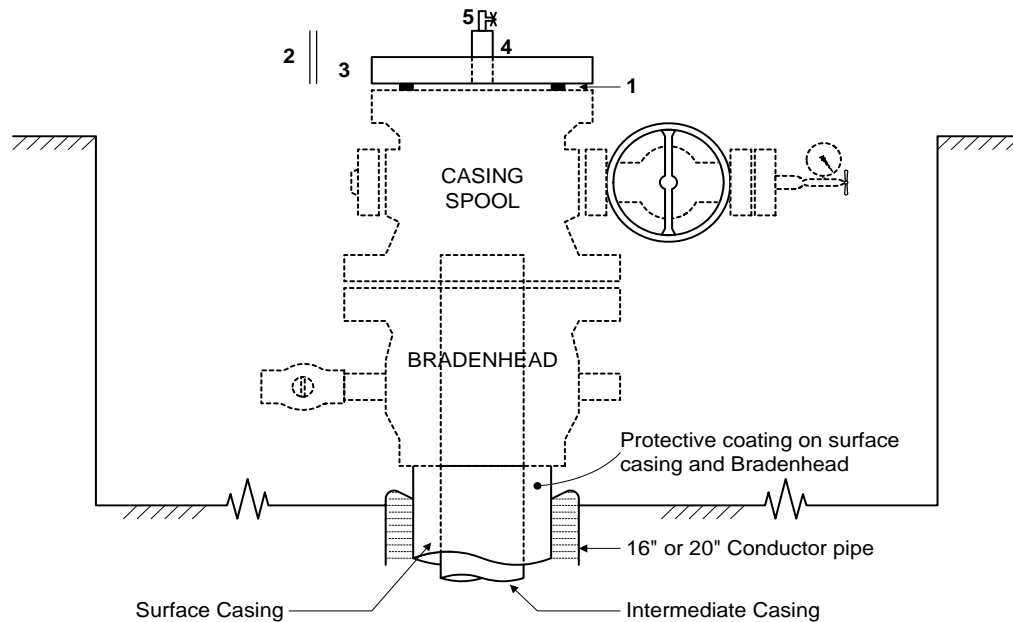
The requirements for suspension and well status schematic diagrams are illustrated below for the following cases:

- Surface casing in place (2 string).
- Surface and intermediate casings in place (3 string).



**Figure 26. Well Suspension Schematic - Surface Casing in Place**

## WELL SUSPENSION - SURFACE & INTERMEDIATE CASING SET (3 STRING)



### MATERIALS REQUIRED

ITEM NO.	QTY.	DESCRIPTION
1	1	RING GASKET
2	As required	STUDS C/W NUTS
3	1	FLANGE TAPPED 2" L.P.
4	1	BULL PLUG 2" L.P. TAPED TAPPED ½" N.P.T.
5	1	NEEDLE VALVE ½" N.P.T. MALE X FEMALE

**Figure 27. Well Suspension Schematic - Surface and Intermediate Casings in Place**

## 11.5 WELL ABANDONMENT

### 11.5.1 Standards

The following standards shall apply to the abandonment of wells:

- Cement plugs should be set to isolate hydrocarbon zones, fresh water zones and zones containing saline water. Cement plugs should also be set across the previous casing shoe and at surface  
The open hole plugs shall extend 25 m below, into another permeable zone if present, and 25 m above the top of the permeable / hydrocarbon zones. Each plug should be a minimum of 50 m in length.
- Only the cement plug set across the previous casing shoe needs to be pressure tested (to LOT plus 100 psi.).
- Excess cement shall be 10% over caliper, or 20% on gauge hole if no caliper is available.
- In the absence of permeable zones the open hole shall be isolated by placing a cement plug across the previous casing shoe to extend a minimum of 23 m below and above the casing shoe. This plug should be pressure tested (LOT plus 100 psi ).
- A surface cement plug of at least 15 m shall be placed in the smallest diameter casing string exposed at surface and between any casing strings not cemented to surface.

### 11.5.2 Procedures

When a well is to be permanently abandoned without running the production casing string, the outline procedure shall be as follows:

1. Set open hole cement plugs as required (see Chapter 8.10 of this Manual for plug setting procedures).
3. Set a 50 m cement plug across the previous casing shoe.
4. Pressure test casing shoe plug ( LOT plus 100 psi ).
5. Set surface cement plug 15 m (50') thick.
6. Nipple down the BOPs.
7. Remove casing spool and Bradenhead (see Spool Removal, below).
8. When the rig has been moved, install the Plug and Abandon Marker Plate. The Standard Marker Plate format is shown in Section 11.5.5.

### 11.5.3 Minimum Mechanical Barrier Summary

Borehole Location	Barrier
Wellbore	<ol style="list-style-type: none"> <li>1. Surface cement plug</li> <li>2. Casing shoe cement plug – must be pressure tested to LOT plus 100 psi.</li> <li>3. Open hole plugs as required</li> </ol>

**Table 68. Minimum Mechanical Barriers - Abandonment**

#### **11.5.4 Removal of Wellhead Equipment**

The following wellhead equipment shall be removed as applicable.

##### **Removal of Spool**

When removing the spool, wellhead equipment shall be handled assuming that it is suitable for refurbishment. The following shall occur:

1. The Spool and/or Bradenhead shall be removed (regardless of condition).
2. The Spool and/or Bradenhead shall be protectively packed and returned to the logistics base for a final decision on whether the item is to be refurbished or scrapped

##### **Surface Casing in Place (2 hole section well)**

On completion of the Abandonment Programme and removal of the BOP's, the Bradenhead shall be removed in one of the following ways:

- Back off the Bradenhead, if not welded.
- If welded cut the surface casing a minimum of 6 inches below the Bradenhead.

##### **Surface and Intermediate Casings in Place (3 hole section well)**

On completion of the Abandonment Programme and removal of the BOP's, the Spool and Bradenhead shall be removed in one of the following ways:

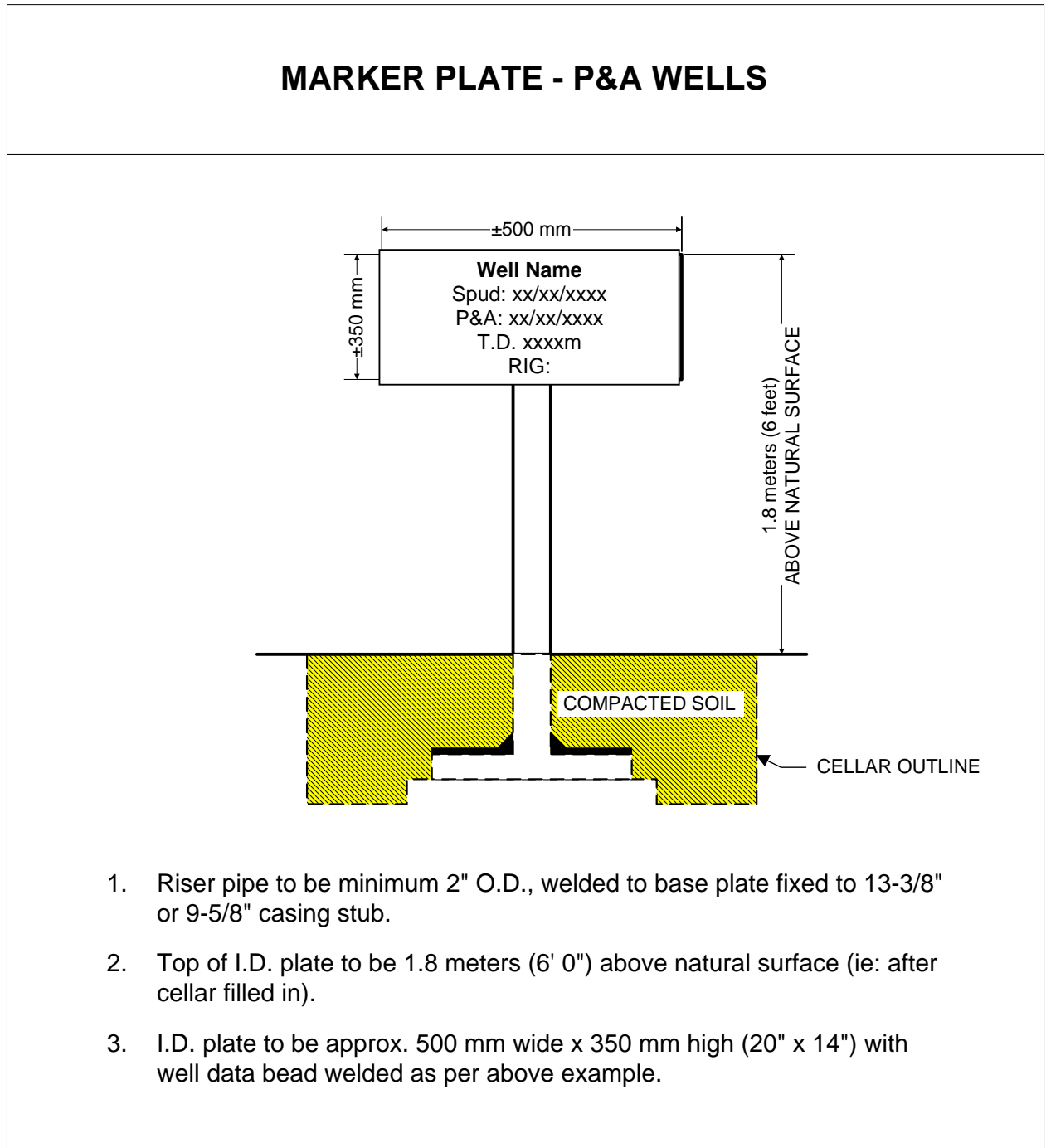
- Cut two diametrically opposed windows in the surface casing to allow cutting access to the intermediate casing. The windows should each extend for a maximum of 1/4 of the surface casing circumference, and the tops should be a minimum of 6" below the Bradenhead.
- Cut the intermediate casing, lift and remove the Spool.
- Remove the Bradenhead as above.

##### **Reporting**

Upon completion of the abandonment operations the DSV shall prepare the Well Abandonment Report.

### 11.5.5 Abandonment Schematic

A standard Plug and Abandon Marker Plate format is given in the figure below.



**Figure 28. Standard P & A Marker Plate Format**

## **11.6 LEASE CLEANUP AND WASTE DISPOSAL**

The following Sections provide a summary of the guidelines given in the lease preparation procedure.

### **11.6.1 Initial Lease Clean-Up**

The DSV shall organise the following initial clean-up of the lease area at or near the time the rig is released. The following work is to be completed prior to the last personnel leaving the site.

- Any water remaining in the Turkeys Nest is to be pumped out so that the maximum amount of plastic pit liner can be recovered. The recovered liner is to be used on the next well location as protection between the shaker tank and the sump. If the water in the Turkeys Nest is required for completion operations the liner should be left in place. The DS will advise if this is required.
- Biodegradable rubbish should be placed in garbage bags, put in the correct segment of the rubbish bins and sent to the appropriate disposal depot.
- For plugged and abandoned wells, the rathole, mousehole and cellar must be filled to the level of the lease surface and compacted.
- For completed and suspended wells, the rathole and mousehole must be filled and compacted, the cellar ring removed and the cellar left unbackfilled.
- All recyclable materials are to be removed from the site and sent to the nearest Waste Management Depot for appropriate disposal.
- Any exposed or re-usable plastic which is lining the area by the shaker tank shall be removed and disposed of in the correct section of the rubbish bins. All other exposed plastic shall be cut off below the surface level in order to be covered once the sump is backfilled.
- A well identification plate (Marker Plate) shall be fabricated and securely installed where it is clearly visible (also see Section 11.5.5 above).
- The site must be cleared of all equipment and materials.
- An Initial Lease Clean-up Report shall be completed.

### **11.6.2 Final Lease Clean-Up**

The drilling manager shall organise for the final clean-up to be conducted. This will include fencing the sump etc as part of the preliminary restoration. Final clean up will restore the lease to as close to original condition as practical.

## **CHAPTER 12 SPECIAL OPERATIONS**

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## 12.1 OBJECTIVES

This Chapter provides an overview of the equipment and procedures used in non-standard drilling operational circumstances. These may be applicable to following personnel:

- Drilling Operations staff.
- Drilling Contractors.
- Specialist subcontractors.

The information contained in this Chapter can be used to improve the understanding of non-standard activities, and identify the alternative methods available.

## 12.2 RESPONSIBILITIES

As this Chapter primarily provides a description of drill string equipment, very few responsibilities have been defined. Those identified are tabulated below.

Task	Performed by	Verified by
<b>Stuck Pipe</b>		
Address potential problems in the Drilling Programme	DM	DM
Conduct drilling operations to avoid stuck pipe	Drilling Contractor	DSV
Troubleshoot and free stuck pipe	DSV/ Drilling Contractor	DM
Run free point indicator logs	Logging Contractor	DSV
Back-off pipe	Logging/ Drilling Contractor	DSV
Decide to sidetrack	DSV/DM	DM
<b>Stuck Logging Tools</b>		
Ensure fishing equipment for all programmed logging tools available on site	DSV	DM
Notify Hobart office of stuck logging tools	DSV	DM
Decide on fishing method	Logging contractor/DSV	DM
Perform fishing operation	Drilling Contractor/ Logging Contractor	DSV
<b>Milling</b>		
Maintain list of milling equipment available at the wellsite / logistics base	DSV	DM
Notify Hobart office of milling requirements	DSV	DM
Decide to mill	DSV/DM	DM
Perform milling operations	Drilling Contractor	DSV
<b>Fishing</b>		
Maintain list of fishing equipment available at the wellsite/ logistics base	DSV/DM	DM
Notify Hobart office of stuck pipe or lost equipment in hole	DSV	DM
Decide to fish	DSV/DM	DM
Mobilise fishing specialist	DSV/DM	DM
Perform fishing operations	DSV / Drilling Contractor / Fishing Specialist	DM
<b>Air Drilling</b>		
Operate and maintain air drilling package	Air Drilling Contractor	DSV
Supervise drilling operations	DSV	DM

**Table 69. Responsibilities for Special Operations**

### 12.3 STUCK PIPE

Drilling is considerably influenced by a large range of lithological conditions. These conditions can cause the following potential drilling-related problems:

- Tight hole due to swelling / reactive clays.
- Cuttings pack-off around drill pipe.
- Differentially stuck drill string (depleted reservoirs)
- Washouts and hole erosion.
- Borehole breakout and hole ovality.
- Hard and abrasive drilling with a potential for key seating.
- Maintaining effective directional control.

The causes and remedies of stuck pipe are described in the remainder of this Section.

#### 12.3.1 Stuck Pipe Risks and Controls

The stuck pipe risks and controls for different hole sections of wells drilled by GSLM are described below.

##### Surface Hole

Hole instability and potential losses are the primary concerns in surface hole. Guidelines to controlling these include. Another potential cause of stuck pipe is the presence of fractured or weathered Diorite which may cause blocks to jamb the drillstring.

- Maintaining an initial low mud weight (essential).
- Maintain good rheology with bentonite and native clays.
- Addition of LCM to minimise losses.
- Using KCl (normally 2-3%) to minimise hydration of clays
- Increasing mud weight at section TD if indicated by hole condition.
- Maintaining good dilution rates (generally >0.5 bbl/ft) to control solids build up.
- Drill Diorite with slick BHA's
- If possible use mineral rig to pre-drill diorite with air.

##### Intermediate/ Production Hole.

Very few wells have been drilled in Tasmania and consequently it is not possible to predict likely problems. It is therefore important to be prepared for hole problems of any type at any time.

A wide variety of sediments and drilling conditions can be expected while drilling these in Tasmania. These will range from less consolidated Tertiary sediments to the hard and consolidated Permian/Ordovician sediments. A Dioritic sill (often fractured), up to 500m thick, is present in most arrears of Tasmania and this has the potential to cause stuck pipe (blocks falling in) and lost circulation.

Guidelines for maintaining optimum hole and drilling conditions include:

- Maintaining a balance between tight hole and losses by control of mud properties, primarily weight.
- Observing careful tripping practices past permeable formations (Monitor Swab / Surge pressures).
- Perform frequent, short wiper trips as indicated by hole condition.
- Taking into consideration the time-dependent nature of drilling reactive clays.
- Keeping pipe moving as much as possible through and below depleted zones.
- Use BHA's appropriate to the interval being drilled.
- Closely monitor the drilling parameters and cuttings for indications of potential problems. i.e. Listen to what the well is saying.
- Don't take short cuts. Do things properly not quickly.

### **12.3.2 Causes of Stuck Pipe**

Stuck pipe falls into the following categories:

- Differential sticking.
- Mechanical sticking.

Prevention of stuck pipe is detailed in General Drilling Practices (Chapter 3.5 of this Manual).

The Appendix at the end of this chapter provides charts for identifying the causes of stuck pipe.

#### **Differential Sticking**

In normal overbalanced drilling conditions, the pressure exerted by the mud column is greater than that of the formation fluids. If the formation is permeable, and the drill string lies against the wellbore wall, the pipe may become differentially stuck due to the build up of filtercake.

#### **Mechanical Sticking**

Mechanical sticking results from one or more of the following conditions:

- Inadequate hole cleaning (cuttings packing off).
- Formation instability (Diorite blocks falling in)
- Key seating.
- Under gauge hole and BHA changes.
- Drilling plastic formations.

### **12.3.3 Freeing Stuck Pipe**

The first actions taken when the drill string becomes stuck greatly influence the chance of freeing the pipe. The following points give guidance on the correct early response. The Driller must be fully briefed on the actions to be taken when hole problems are expected.

### **Differentially Stuck Pipe**

The force necessary to free differentially stuck pipe depends upon the following factors:

- The pressure differential between the wellbore and the formation fluid pressure.
- The area of the pipe surface which is embedded in the filter cake.
- The sticking force, which is directly proportional to the coefficient of friction between the pipe and the wall cake, may increase with time.

The correct early response to free differentially stuck pipe is:

1. Jarring shall commence by immediately pulling the pipe to the maximum safe pull specified for the assembly and drilling rig.
2. If pulling and jarring are not immediately successful, the pipe may be slumped and right-hand torque applied in an attempt to free the pipe.
3. The pipe should continue to be worked and circulation continued while preparing the pipe lax pill.

A pipe lax pill shall be spotted at the stuck point as soon as possible after initial attempts to mechanically free the pipe have failed.

### **Mechanically Stuck Pipe**

The pipe should be immediately worked and jarred in the opposite direction to that when it became stuck i.e. if stuck when POOH, jar down, if stuck when drilling or RIH, jar up.

#### **Notes:**

- The maximum safe pulling limits for the pipe and rig should be determined prior to any jarring operations.
- Pipe should be pulled to the maximum safe limit for the assembly and rig (whichever is the least). If the first attempts to free the pipe are unsuccessful, the pipe should be worked in both directions until alternative action can be taken.
- Before using any lubricating pill, the effect on the hydrostatic pressure in relation to the pore and fracture pressures shall be taken into account.
- The overpull to trip the jars safely may not be as high as the maximum safe pull for the BHA.
- If circulation is not possible and the drill pipe is pressured in an attempt to initiate circulation, the pressure applied shall not exceed the Maximum Allowable Annular Surface Pressure (MAASP) without the prior approval of the DM.

### **Determine Effective Pull on Stuck Pipe**

When determining the pull on stuck drill pipe, the actual weight of the string in air is to be used, and not the indicated weight, as recorded by the weight indicator. A worked example is given below:

DEPTH;	10.000'
Weight of drill collars in air = 743' of 6 ½" OD x 3" ID = 743 x 89	66,100 lb
Weight of DP in air = 9,257' x 20.77 lb/ft	192,200 lb
Total weight of string in air	<b>258,300 lb</b>
Indicator reading	205,000 lb
Weight of hook, blocks, swivel, etc.	27,000 lb
Pull reported at 100,000 lb over indicator reading	305,000 lb
Less hook, block, swivel, etc.	-27,000 lb
Effective pull on string	<b>278,000 lb</b>
Assuming that pipe is stuck on bottom, then the effective pull at the stuck point = 278,000 - 258,300 (no buoyancy of pipe)	<b>19,700 lb</b>
In order to apply a pull of 100,000 lb at the bit, the Indicator reading would have to be 258,300 + 27,000 + 100,000 lb.	<b>385,300 lb</b>
This would mean that the pull on the pipe amounts to 385,300 - 27,000	<b>358,300 lb</b>

**Table 70. Worked Example for Determining Effective Pull on Stuck Pipe**

### Reducing Hydrostatic Pressure

Reducing hydrostatic pressure is the best way of freeing differentially stuck pipe.

However, it is essential that all aspects of well control be considered before lowering the hydrostatic head.

The preferred method of reducing hydrostatic pressure is to reduce the mud weight. However, pills to reduce the overbalance may be spotted. Close attention must be paid to all kick indicators.

### Spotting Pipe Release Agents

Differentially stuck pipe can be freed by spotting pipe-free pills at the earliest possible opportunity. The volume of spotting fluid depends upon the annular volume at the stuck point, the length of section thought to be stuck and the ID of the BHA/DP

- Once the pill is in place, it must be left to soak whilst continuously working the pipe. Soaking times of at least 12 hours should be considered.
- During soaking, the pipe should be worked, preferably by putting it in compression. Slack off about 10,000 lb below the weight of the pipe and put in some right-hand torque. The amount of torque should be roughly half a turn for every 1000' of pipe above the suspected stuck point.
- Mix enough soak pill to cover the BHA plus additional volume of 5-8 bbls to move the soak pill approximately 1 bbl every 30 minutes.
- Consider mixing pill at twice the suppliers recommended concentration
- A bradenhead squeeze may be considered if initial attempts fail.

## Jar Applications

There are two types of jars. These are described in the table below.

Jar Placement	Guidelines
Drilling Jars	<ul style="list-style-type: none"> <li>• Normally run in the string and available as hydraulic or mechanical</li> <li>• In fishing operations, the jar is located directly above the fishing tool (i.e. overshot). Two to four drill collars should be placed above the jar.</li> <li>• Jarring performance will be reduced if there is a large difference between the drill collar/HWDP size above and below the jar.</li> <li>• Jarring performance will be reduced if there is a large difference between the drill collar/HWDP size above and below the jar.</li> <li>• Do not drill with the jars at their neutral point. A jar accelerator or “intensifier” may be run above the drill collars placed over the jar (between the drill collars and drill pipe) thus greatly increasing the effectiveness of the jarring action. Less drill collars may be run when an accelerator is used.</li> </ul>
Surface Jars	<ul style="list-style-type: none"> <li>• Used to jar downwards, for example to release key-seated pipe</li> <li>• The impact load can be adjusted, and jarring action is usually light to begin with, gradually increasing in intensity.</li> <li>• It is important not to pre-set the trip weight above the weight of the string that is free. Jars are located at surface below the kelly, or a stand can be placed above them.</li> </ul>

**Table 71. Guidelines for Jar Types**

### Jar Placement

In straight holes the jars shall normally be located two to four drill collars below the top of the BHA (never directly below the drill pipe or HWDP).

In deviated wells the jars may be placed lower in the BHA and run under compression.

Jars should never be run in neutral, as this will cause them to fail prematurely.

When determining jar placement, it is essential to ensure that the jars are run in tension and that there is sufficient buoyant weight of drill collars below them, plus 15% safety factor.

The following jarring practices shall be followed:

- Ensure that all surface pulling equipment is in good working condition.
- Ensure that both the weight indicator and deadline anchor are correct and clear of debris.
- Visually check the derrick for loose fittings.
- All personnel must be kept clear of the derrick and drill floor while jarring
- Pull shall be limited on stuck pipe to 85% of the minimum yield strength of the weakest member.
- When jarring, overpull to the maximum figure to trip the jar, wait for the jar to trip, then increase the overpull to that recommended for the pipe.
- Regularly inspect the derrick and drill floor for damage.

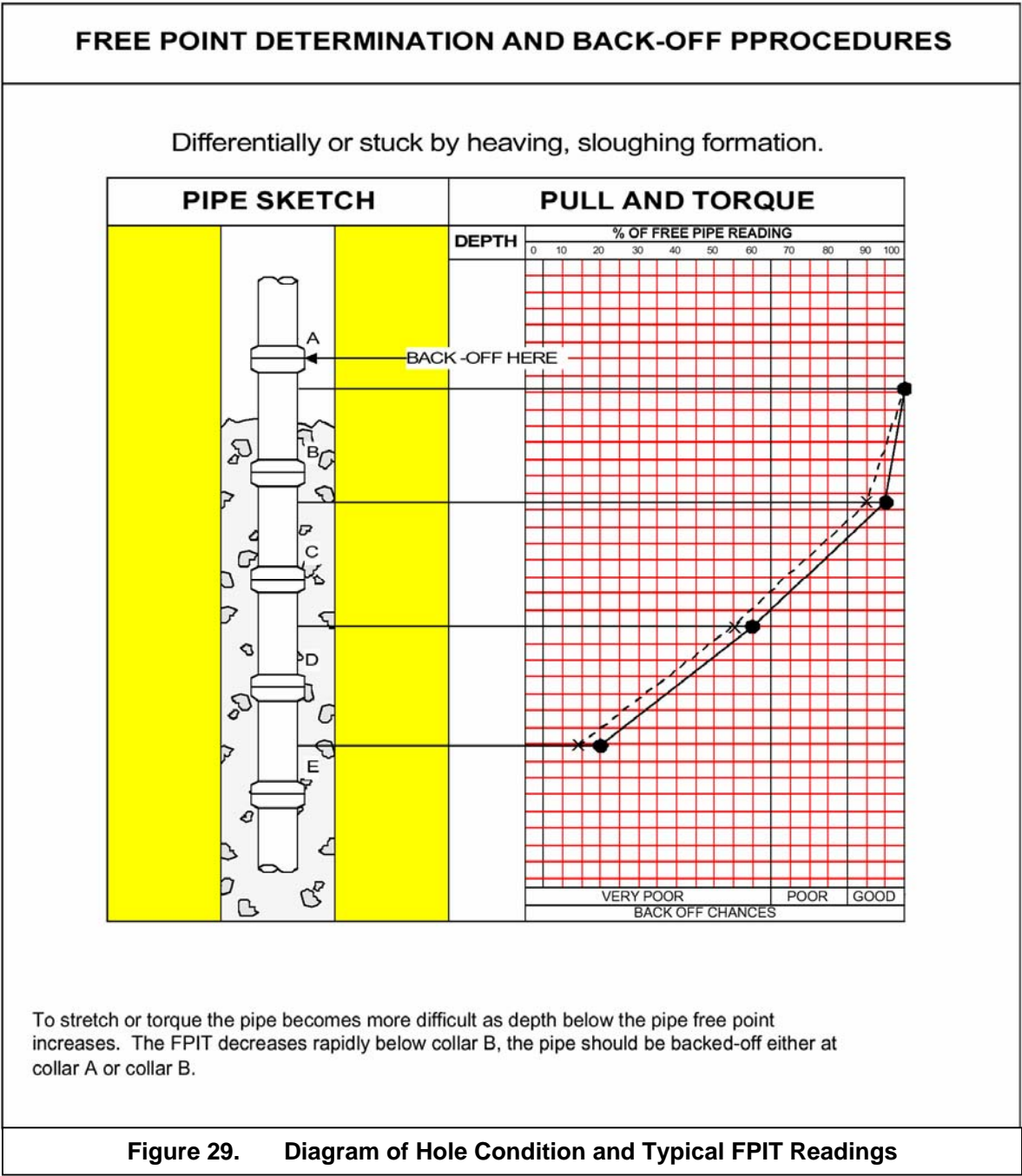
**Note:** Whilst circulating, pump-open forces greatly influence jarring performance and have to be carefully considered.

### Free Point Determination

There are two methods to determine Free Point. These are tabulated below.

Method	Application
Stretch Method	Stuck point can be established by stretching the string and using the stretch charts for drill pipe. This method gives only an approximate value for the free point and should only be used to find the approximate stuck point for spotting pipe free pills and providing a starting point for using the Free Point Indicator Tool (FPIT).
Free Point Indicator Tool (FPIT)	This tool can be run on electrical wireline in order to back-off the string at the deepest possible point. By applying stretch and torque on the pipe, the FPIT can determine elongation or rotation at any depth. A plot of depth versus the percentage of surface torque and pull transmitted downhole shows the deepest point at which the string is free. This plot is shown overleaf.

**Table 72. Free Point Determination Methods**





### 12.3.4 Procedure for Backing-Off the Pipe

Before backing-off the pipe, the string shot size, weight, torque and turns on the string must be considered.

The string shot shall be determined by the Wireline Logging Contractor so that it is large enough to back-off the joint to be released without splitting the pipe. If the pipe does not back-off after the first shot, the charge can be increased on subsequent runs. The size of the primer cord bundle must be confirmed to be small enough to pass through the minimum pipe ID (this may be the jars).

Ideally the neutral point of the string weight distribution should be at the back-off point. The required surface pull to obtain a neutral point at the planned back-off point should be carefully determined when running the Free Point Indicator Tool.

### Working Torque Down the Hole

Before working torque down the hole, the following safety precautions must be adhered to:

- Tong and slip dies must be clean and sharp and of the correct size.
- Tongs and back-up lines must be attached and in good condition.
- Slip handles should be tied together to prevent them jumping out of the rotary table in case the string parts high.
- Elevators should be latched around drill pipe but free from the tool joint, leaving the pipe free to rotate.
- The hook must be unlocked during rotation of the drill pipe.
- The possibility of residual torque when the drill pipe is first picked up must be considered. This may cause the slips to spin out of the rotary table.
- All non-essential personnel must be removed from the drill floor.

The procedure for working torque down the hole is as follows:

1. Set the string to the determined weight for back-off.
2. Mark the pipe at the top of the slips, and refer to that mark at all times (not the weight indicator as wall friction may give misleading effects on the weight reading).
3. Apply half of the left-hand torque required and lock the rotary table. Use a tong line and the rotary tongs to relieve the torque and unlock the rotary table, and hold the torque with the tongs.
4. Slowly pick up the string off the slips and work the pipe vertically several times, being careful not to go below the "weight" mark on the drill pipe, as the pipe could then part at some random point.
5. Set the pipe back in the slips at the weight mark and lock the rotary table at the applied torque.
6. If it is judged that the pipe will accept the remaining left hand torque, proceed to apply this. If not, apply half the remaining torque, in either case repeating the above procedure until all the required amount of left hand torque is in the drill pipe.

**Note:** Before applying left hand torque, torque the string to the right and note the torque-gauge reading. When later applying reverse torque, the torque reading should not exceed the maximum observed while torquing to the right.

### **Completing the Back-off**

After the string shot has been detonated, check for back-off by picking up the string. In some cases the pipe may have only partially backed-off. To complete the back-off the following procedure must be followed:

1. Before applying left hand torque, torque the string to the right as before.
2. Apply approximately half the amount of left-hand torque originally used to back-off the string. While the torque is being applied, the pipe should back-off with a corresponding loss of torque load. If the pipe does not come free, release the torque in a controlled manner and note any loss of torque in the process
3. Repeat the process until back-off is completed.
4. After accomplishing the completed back-off, POOH.

## **12.4 STUCK LOGGING TOOLS**

The wellsite geologist must be involved with all wireline logging tool fishing operations.

Logging tools may become stuck in either open or cased hole. The scenarios are described below

### **12.3.1 Open Hole**

When a logging tool becomes stuck in open hole and all attempts to free it have failed, the following options exist (in order of consideration):

1. Strip over (cut and thread) the wireline cable to recover the tool.
2. Break the cable weak point and fish the tool.
3. Cement the tool in place.

The primary approach on all fishing operations (including tools with radioactive sources) should be to strip over the cable. This will minimise the risk of failing to fish the tool in an open hole configuration

Radioactive logging tools stuck in open hole shall always be fished by the stripover method. Under no circumstances shall the cable weak point be intentionally broken without the approval of the logging company and the DM. Reverse-strip out of hole.

For logging tools containing radioactive sources, the option of cementing in place may be subject to special regulations obtained through consultation with Mineral Resources Tasmania.

### **12.3.2 Cased Hole**

For logging tools stuck in cased hole, the normal approach is to stripover the cable. As this will minimise the risk of the tool dropping free into open hole.

### **12.3.3 Stripping Over the Wireline Logging Cable**

The following preparation shall be performed before stripping over the wireline logging cable.

#### **Equipment**

The following should be supplied by the Wireline Logging Contractor, and available on site for every logging tool to be run downhole.

- Fishing equipment (i.e. overshots) specific to the stuck tool.
- Additional tension meter with cable tension read-out for the Driller.
- 82 m of ¼" rope to control the run of cable going over the top sheave (if required).
- 27 m of ½" rope to hold the lower sheave straight (if required).
- Intercom between logging winch unit and drillfloor.
- Diagram of all tools with lengths, OD's, fish neck OD and length

## Personnel

In addition to the regular drilling crew, the following personnel should be available throughout the stripping over operations:

- An experienced winch operator.
- One person at the rotary to engage and release the spear overshot.
- A Wireline Logging Operator on the drill floor to monitor the operation.

## Preparation

An indicative sequence of events during the stripping over of wireline logging cable is tabulated below. The actual sequence will be determined by the Logging Contractors procedures.

Task	Preparation
1. Prepare Overshot	<ul style="list-style-type: none"> <li>• Inspect, lubricate and dress the overshot contained in the loggers fishing kit.</li> <li>• Check the top end to ensure that the 2 3/16" bushing is in place. This holds the 2 1/4" hexagonal adapter of the lower rope socket, if the cable is dropped at the surface.</li> </ul>
2. Prepare Cable for Cut	<ul style="list-style-type: none"> <li>• Secure the cable clamp (T-bar) to the cable, just above the rotary table.</li> <li>• Lower the cable until the cable clamp is supported by the rotary table.</li> <li>• Continue slacking off the cable, then cut it at a point 4 - 6' from the cable clamp, and secure the ends.</li> </ul>
3. Re-rig the Derrick	<ul style="list-style-type: none"> <li>• Position the lower sheave so that it does not interfere with drill floor operations, and hang the upper sheave from one of the main derrick beams, well above the drill pipe stand, in such a position that it does not interfere with the travelling block.</li> </ul>
4. Prepare Cut and Thread Assembly	<ul style="list-style-type: none"> <li>• Fit rope sockets to both ends of the logging cable (standard types preferred).</li> <li>• Make up the remainder of the assembly, i.e. spearhead, spearhead overshot, swivel, and sub. Sinker bars may be added to the catcher assembly to provide the necessary weight.</li> </ul>
Perform Full Test	<ul style="list-style-type: none"> <li>• Latch the spearhead overshot to the spearhead while the cable clamp remains on the cable. Mark the cable adjacent to each rope socket with tape and test the cable with 2.5 MT tension for one minute. The end of the cable should be passed through the (fishing) overshot before the hex-adapter is replaced.</li> </ul>

**Table 73. Preparation of Stripping Over Wireline Logging Cable**

## Running in the Hole

The procedure for running in the hole while stripping over the logging cable is:

1. Pick up the first stand of drill pipe and install cross-over subs as required.
  - A circulating sub should be installed in all fishing strings
2. Draw the spearhead overshot up to the derrick man, who can then thread it through the first stand of drill pipe. If the sinker bars make the assembly too stiff to pass the travelling block, the assembly should be fed into each stand before it is picked up.
3. Attach the spearhead overshot to the spearhead and make-up the fishing overshot with chain tongs onto the bottom of the first stand.
4. With tension in the cable, check the operation of the remote tension indicator, then remove the cable clamp.
5. Complete the make up of the fishing assembly with the rig tongs.

6. Run the first stand into the hole:
  - Maintain a depth tally.
  - Maintain the cable tension to Wireline Logging Contractor specifications, paying close attention to the tension indicator.
7. Install the "C" plate and slack-off the cable until the slot in the spearhead is supported by the "C" plate.
8. The cable is now flagged for reference at each stand of drill pipe.
9. Release the spearhead overshot. Thread it through the next stand, and re-connect it to the spearhead.
10. Pull tension in the cable and remove the "C" plate. Make up the second stand onto the first and repeat the whole process for each stand.
11. Run in slowly and carefully, (according to the points listed in item 6), thus avoiding the following primary hazards:
  - The cable being dropped.
  - Broken armour wire balling-up ahead of the overshot.
  - The impact of the overshot on a bridge cutting the cable.
  - If the cable becomes key-seated it may double-back round the overshot.

**Note: Do not rotate the pipe in the hole.**

12. When approaching the depth of the fish, it is good practice to clean out the fishing tool by circulating. Circulation at a bridge, at the fish, or during engagement of the fish is accomplished by hanging the cable spearhead on a bushing in a special circulating sub.
  - With the spearhead hanging on the "C" plate, thread the circulating sub and adapter sub over the spearhead overshot. Latch the spearhead overshot onto the spearhead, lift the cable and remove the "C" plate.
  - Make-up the subs onto the drill pipe. Place the special bushing over the cable and into the circulating sub. Lower the cable until the rope socket rests on the bushing. Unlatch the spearhead overshot.
  - Make up the kelly onto the circulating sub, using the appropriate cross-overs.
  - When the overshot is a short distance from the fish, the fish may come free. If this occurs circulation may be used to clean the overshot and then the logging tool can then be pulled into the grapple. The fish may, however, be covered by formation solids, requiring the overshot to be circulated down onto the fishing neck. In this case the overshot must reach the fish with sufficient tension still in the logging cable to prevent it going slack and looping over the rope socket.

### Engaging the Tool

The fish can be engaged when the original tension at surface, including the weight of the logging tool, is known and the elongation (stretch) per 10,000' of standard logging cable sizes with respect to tool weight, has been determined from charts supplied by the Logging Contractor. The fish shall be engaged as follows:

1. Pull on the logging cable with the original logging tension and check the elevation of the spear point.
2. From the Logging Contractor's chart, find the cable stretch due to the weight of the logging tool in mud.

3. The elevation minus the stretch gives the elevation of the spear point for neutral tension in the cable at the logging tool. Space out the string with pup joints so that the spear point is below this elevation when the overshot engages the fish.
4. If circulating over the fish, continue pumping while lowering the pipe and engaging the fish. An increase in both pump pressure and cable tension should be noted as the tool head enters the overshot.
5. Stop circulating.

### Pulling the Tool

After proving, by motion of the pipe and its effect on the cable tension, that the fish is engaged, the cable weak-point may be broken by:

1. Installing the cable clamp.
2. Latching the elevators around the cable, (under the cable clamp).
3. Pulling slowly until the weak point breaks.

The following procedure shall be adhered to:

1. Cut the cable to remove the rope sockets, then tie the two ends together with a reef knot. Tape the loose ends onto the logging cable to prevent them hanging up as they pass over the sheaves.
2. Spool the cable onto the winch, then pull the fish out of the hole.
3. Do not rotate because the fish may disengage from the overshot.

### Problems while Stripping over the Cable

The following problems listed in the text and table below may be encountered whilst stripping over the wireline logging cable:

- If the spearhead rope socket fails, then a broken cable is left in the hole.
- If the spearhead with rope socket and cable is accidentally dropped into the pipe, run the thread through the overshot with the largest applicable guide down the pipe and attempt to engage the spear. If this fails, the drill pipe can be pulled because the bushing in the fishing overshot will catch the hexagon adapter on the spearhead.
- If a bridge is encountered, it should be removed by circulating gently.

The table below highlights some of the causes of changes to the cable which may occur when stripping over the cable.

Cable Tension	Cause
Increases Sharply	<ul style="list-style-type: none"> <li>• The cable may be stuck in a key-seat and doubled back outside the overshot.</li> <li>• Picking up the pipe should cause a small decrease in tension. Increase the cable tension and the guide should free the cable ahead of the advancing overshot.</li> </ul>
Increases Moderately Fast	<ul style="list-style-type: none"> <li>• A broken armour cable may be balling up at the overshot.</li> </ul>
Increases Gradually	<ul style="list-style-type: none"> <li>• This is normal for a deviated well. The elevation of the spear point will be lower.</li> <li>• If the spear point becomes lower than the top of the pipe during running in, a short length of spacer bar may be introduced between the rope socket and spearhead.</li> </ul>

**Table 74. Increase in Cable Tension – Problems Whilst Stripping**

## 12.5 MILLING

For the purposes of this Chapter, milling is defined as any non-planned milling of junk in open hole and in casing.

### 12.5.1 General Milling Guidelines

To effectively remove the cuttings while milling, the following should be adhered to:

- A minimum annular velocity to keep flow turbulent around the BHA should be used to prevent cuttings “bird nesting” and blocking the annulus.
- The Yield Point of the mud should be increased as high as possible before commencing milling.
- Viscous pills should be pumped if required.

Washing should begin at least one single above the fish. The fish should be tagged, the string picked up and rotation/washing started a minimum of one foot above the fish as the string is lowered. Weight and RPM should be adjusted to find the best milling rate while noting the rotating torque.

The table below tabulates some of the considerations to be made during milling operations.

Topic	Milling Considerations
Rotation	<ul style="list-style-type: none"> <li>• Milling should be conducted using high rpm according to milling equipment manufacturer's instructions.</li> </ul>
Weight	<ul style="list-style-type: none"> <li>• A constant milling weight should be maintained.</li> <li>• The tool must not be allowed to drill off.</li> </ul>
Monitor and Record	<p>While milling, the following parameters must be monitored and recorded: - Progress made</p> <ul style="list-style-type: none"> <li>• Weight on mill</li> <li>• Torque</li> <li>• RPM</li> <li>• Pump pressure</li> <li>• Circulation rate</li> <li>• Description of milled cuttings</li> <li>• Any relevant observation</li> </ul>

**Table 75. Considerations During Milling**

- In order to provide a high circulation rate, all subs and auxiliary tools should be full bore where possible. The tool must be picked up, circulated and rotated at regular intervals.
- BOP cavities must be flushed on completion of milling.
- The running of jars in the milling string should be considered on a case-specific basis.
- Stabilisers should be run to centralise the mill, but the number of stabilisers must be kept to a minimum to prevent excessive torque and bird nesting of cuttings.
- Ditch magnets should be used at the shale shakers or flowline. These magnets must be cleaned regularly and the weight of steel recorded.
- When milling junk, spudding should be periodically carried out to pound junk down to the bottom of the hole where it can be effectively milled.

The following table contains a summary of general operating recommendations and normal milling rates.

Type	RPM	Weight (1000 lb)	Remarks
Junk Mill	100+	10 - 50	Spud mill from time to time
Pilot Mill	125+	6 - 20	Vary weight to find best ROP
Taper Mill	50 - 80	6 - 30	Start with light weight & low rpm
Economill (Flat Mill)	100+	2 - 40	Start mill above fish
Rotary Mill	50 - 100	5 - 20	Pick up from time to time. Check overpull and torque

**Table 76. General Operating Recommendations For Milling Operations**

Material	Junk Mill	Pilot Mill	Flat Mill	Rotary Shoe/ Washover Shoe
Drill pipe	2.0 - 6.0	2.0 - 6.0	-	6.0 - 20.0
Drill Collars	1.0 - 2.0	1.0 - 2.0	-	4.0 - 6.0
Packers	4.0	-	2.0 - 3.0	2.0 - 4.0
Bit Cones, etc.	2.0 - 4.0	-	-	-
General Junk	3.0 - 5.0	-	2.0 - 4.0	-
Washover Pipe	2.0 - 4.0	4.0 - 6.0	-	-

**Table 77. Expected Milling Rates ( ft / hr. )**

### 12.5.2 Guidelines on Milling Junk

Guidelines for milling junk are tabulated below.

Milling Junk	Guidelines
In Open Hole	<ul style="list-style-type: none"> <li>The mill should be only 1/8" to 1/4" less than the open hole diameter.</li> <li>A junk sub should be placed in the milling assembly.</li> </ul>
Inside Casing	<ul style="list-style-type: none"> <li>A non-rotating stabiliser may be run above the mill with the same OD as the mill head, which should be approximately the same as the drift ID of the casing.</li> <li>At least one junk sub should be placed in the milling assembly.</li> <li>No cutting action on sides of mill (to avoid damage to casing).</li> </ul>
With a Pilot Mill	<ul style="list-style-type: none"> <li>A mill of similar diameter to the fish diameter should be used but stabiliser blades should be larger than the OD of the fish to be milled if hole conditions allow.</li> </ul>
With a Taper Mill	<ul style="list-style-type: none"> <li>The diameter of the taper mill should be equal to the enlargement required.</li> <li>Rotate slowly while entering the fish.</li> <li>After the restriction has been enlarged, the rotation can be increased to 80-100 rpm while reciprocating the mill through the interval several times</li> </ul> <p><b>Note:</b> The weight on the mill should be kept as low as possible. Beware of torque-up exceeding 80% of drill collar make-up torque.</p>

**Table 787. General Guidelines to Milling Junk**



## **12.6 FISHING**

This Section describes practices, tools and procedures used by GSLM during fishing jobs.

### **12.6.1 General Fishing Guidelines**

In the event that equipment becomes lost or is stuck in the hole, the drilling should be notified immediately by the DSV. The decision to mobilise fishing specialists shall be made by the DM.

In principle, the preferred method of fishing shall be the overshot method. However, each case will be evaluated individually.

The following considerations (and questions) should be considered in deciding the optimum course of action:

- The type of equipment in the hole to be fished (drill pipe, collars, junk, bit cones, etc.).
- The fishing profile presented.
- The condition of the hole/mud. Will formation instability cause the hole to deteriorate?
- Is the fish stuck? If yes, what is causing it to be stuck?
- What is the probability of freeing the fish?
- Can tools be run inside the fish or should they be run outside it?
- Will wireline tools have to be run through the fishing assembly?
- What are the anticipated times and costs to free the fish?
- What is the optimum economic fishing time? (Economics shall be performed by the DE).
- Are there open reservoirs below the fish? Does this have any implications for well control?
- Is it necessary to run a pump out (or circulating sub) above the overshot in order that the well can be circulated in the event of a pack-off after engaging the fish?.

## Classification of Fishing Tools

The table below shows a general classification of types of fishing tools and their applications.

Type of Fishing Job	Type of Fishing Tool	Names of Tools
Recovery of Tubular Fish	Connecting Tools <ul style="list-style-type: none"> <li>External catch</li> <li>Internal catch</li> <li>Accessories</li> </ul>	<ul style="list-style-type: none"> <li>Overshot</li> <li>Die collar</li> <li>Taper tap (poor class of tool: overshot always preferable if available)</li> <li>Spear (provides very good connection)</li> <li>Bent drill pipe single</li> <li>Hydraulic knucklejoint</li> <li>Hydraulic wall hook</li> <li>Wall hook</li> </ul>
	Washover Tools	<ul style="list-style-type: none"> <li>Washover safety joint</li> <li>Washover pipe</li> <li>Washover shoe</li> </ul>
	Force Multiplier Tools	<ul style="list-style-type: none"> <li>Jar, hydraulic or mechanical</li> <li>Bumper sub</li> <li>Surface bumper jar</li> <li>Accelerator</li> <li>Hydraulic pulling tool</li> </ul>
Recovery of Fish	Disengagement Tools	<ul style="list-style-type: none"> <li>Safety joint</li> <li>Bumper safety joint</li> <li>External tubing/drill pipe cutter</li> <li>Internal tubing/drill pipe cutter</li> <li>Flash cutter (Schlumberger, etc.)</li> <li>Jet cutter (Halliburton, etc.)</li> <li>Chemical cutter (Schlumberger, etc.)</li> <li>Electrical cable back-off (Schlumberger etc.)</li> </ul>
Recovery of Non-tubular Fish	Information Tools	<ul style="list-style-type: none"> <li>Impression block</li> <li>Free Point Indicator</li> <li>Junk basket</li> <li>Circulating junk basket (+ coring)</li> <li>Reverse-circulate globe-type basket</li> <li>Magnet</li> <li>Wireline spear</li> <li>Junk sub</li> <li>Milling shoe</li> <li>Packer retriever</li> <li>Section mill</li> <li>Jet bottomhole cleaner</li> </ul>

**Table 79. Classification of Fishing Tools.**

The fishing equipment carried by the drilling rig shall be specified in the Drilling Contract.

## Fishing Equipment

The following fishing equipment should be available at the well site or from a third party supplier:

- Overshots and oversized guides complete with baskets grapples and mill control to catch all sizes of tools in hole.
- Fishing bumper sub (18" stroke) matching with drill collar string in use.
- Hydraulic jar with matching accelerator for the drill collar string in use.
- Surface jar with matching drill pipe connections.
- Reverse circulating junk basket.
- Junk sub with the same or larger OD as the drill collar strings.
- Lead impression blocks for the various hole sizes.
- Flat mills for all hole sizes.
- Pump out sub or circulating sub.

### 12.6.2 General Practices

The table below defines some of the preparation to be performed before a fishing job.

Task	Preparations Before Fishing
Timing	<ul style="list-style-type: none"> <li>• The maximum economical fishing time shall be determined by the DM</li> </ul>
Recording	<ul style="list-style-type: none"> <li>• All fishing tool details must be recorded on a drawing before running the tool. The safe working load for all fishing tools and associated equipment must be determined.</li> </ul>
Equipment	<ul style="list-style-type: none"> <li>• If the fishing operation involves jarring, refer to Chapter 4.5 of this Manual and remainder of this Chapter.</li> <li>• Internal diameters of fishing tools to be run must be checked to verify that back-off tools can pass through them.</li> <li>• A bumper sub should be considered for use in all fishing assemblies.</li> </ul>

**Table 80. Considerations to be Made Before Fishing**

The following guidelines shall be adhered to when fishing:

- Where a twist-off has occurred, the fish should be tagged before pulling out of the hole and the pipe should be strapped on the trip out.
- If a twist-off occurs while drilling and hole conditions permit the hole should be circulated clean and mud conditioned before pulling out of the hole.
- Determine the size, shape, and condition of the fish. Ensure that a detailed drawing is sent to the DM.
- The pull must be limited to 80% of the minimum yield strength of the weakest point.
- Before connecting to the fish, the following information must be obtained:
  - Establish circulating pressures and rates.
  - String weight up/down and rotating (with and without circulation).
  - Free rotating torque of string.
  - Pipe stretch and stroke of bumper sub, jars, etc.

### 12.6.3 Force Multiplying Tools

The purpose of force multiplying tools is to generate controlled blows onto a stuck fish. These blows can be in an upward direction, a downward direction, or selectively applied in either direction.

Force multiplying fishing tools are divided into three groups as described in the table below:

Tool	Guidelines
Jars	<ul style="list-style-type: none"> <li>Mechanical or Hydraulic (see Stuck Pipe section of this Chapter)</li> </ul>
Jar Accelerators (Intensifiers)	<ul style="list-style-type: none"> <li>A gas charged (N<sub>2</sub>) accelerator or “intensifier” may be run above the drill collars placed over the jar (between the drill collars and drill pipe), greatly increasing the effectiveness of the jarring action. These are also available in double-acting mode, to match the jar action. Typical accelerator strokes are 6 - 15” depending on the tool used.</li> <li>When used, less drill collars may be run without reducing the jarring impact force.</li> <li>Jarring can be conducted at shallower depths where less string stretch and overpull is available, preventing the jar from achieving a full blow.</li> <li>Use of an accelerator, by maximising the impact of the jar and reducing the shock load effect on the string, can significantly enhance the jarring impact force.</li> </ul>
Bumper Subs	<ul style="list-style-type: none"> <li>Often used in conjunction with jars.</li> <li>Provide a means of delivering upward or downward blows.</li> <li>The sub should be installed immediately above the fishing tool or safety joint. Its presence assists operators to release the fishing tool in the event that the fish cannot be freed.</li> <li>Delivers a sharp downward blow as well as transmitting torque required to break the fishing tool engagement and release it from the fish.</li> </ul>

**Table 81. Force Multiplying Fishing Tools**

These tools are most effective when used by an experienced operator who can prevent severe damage to surface equipment and/or the string.

#### Procedure to “Bump Down” in the Hole

- Pick up the string enough to open the tool completely and take a strain or stretch in the string. This shall be the length of the stroke plus the permissible stretch in the fishing string.
- Drop the string to within 6” of the closed position of the tool and stop the string abruptly.
- If sufficient stretch has been taken in the string, the lower end of the fishing string should bump downward closing the bumper sub and, due to the elasticity of the string, deliver a series of downward blows to the tool below the sub.

#### Procedure to “Bump Upwards” in the Hole

- Pick up the string enough to open the bumper sub completely plus a moderate strain or stretch in the string.
- Drop the string a distance equal to the stretch taken only and stop the string abruptly. This should cause the lower end of it to spring downward closing the bumper sub slightly. The string should rebound causing the bumper sub to open quickly and deliver a solid upward blow.

#### **12.6.4 Overshot Tools**

The following general considerations shall be made when planning the use of overshot tools:

- Grapple sizing should be taken from the manufacturer's specification. However, grapple sealing ID should not be more than 1/16" less than the fish OD.
- A pack-off should always be installed in order to circulate through the fish before pulling out of the hole.
- If the hole size is appreciably larger than the overshot OD, an oversized guide may be considered.
- If the pipe is lying in a recess or against the side of the hole, a hook wall guide or bent joint may be considered.
- If the fish cannot be engaged, an extension sub and a milling guide may be considered. A milling guide should always be run with a basket grapple.
- A basket grapple with long catch stop may be considered to catch an upset or box section of a tool joint.

#### **Guidelines Before Engaging Fish**

With the overshot directly above the fish, a combination of rotating and lowering shall result in the following:

- The guide directs the fish into the overshot.
- The fish can easily pass through the grapple because of its helical shape and mode of rotation.
- Too much rotation can damage/wear the grapple.

When lowering the overshot over the fish and once a pressure increase is noted, circulation must be stopped in order to prevent damaging the seal/packer. Bleed off any pressure trapped before engaging the fish.

The penetration of the fish into the overshot grapple must be limited in order to facilitate release from the fish. If the basket grapple used is not a long catch stop type, a stop must be used to prevent the grapple going completely over the upset of the fish. Not doing this makes it almost impossible to release the overshot from the fish.

#### **Guidelines Before Releasing Fish**

Unless an upward strain is maintained, the fishing string must never be rotated to the right while an overshot is engaged on the fish, other than when attempting to come off the fish. Left hand torque tightens the grapple bite on the fish so right hand rotation can be used to release the grapple and come off the fish.

When the fish is properly located in the overshot, exert an upward pull. The grapple shall be contacted by the upward taper in the bowl and the fish held securely. The pack-off rubber seals around the fish, enabling fluid to be forced down through the fish.

Before the start of releasing operations, the weight of the fishing string should always be bumped down, to put the neutral point at the grapple.

The grapple can be freed from the bowl by lowering the string weight or bumping down against the fish. By slowly rotating to the right and slowly raising the string, the spiral grapple unwinds or the basket grapple expands disengaging the string from the fish.

### 12.6.5 Spears

Spears should be dressed with a pack-off rubber to circulate when required. A stop ring or stop sub should be used to prevent the spear from entering too deeply into the fish. Using these also enables setting of the jars and easier release of tool.

The fishing string should be bumped down before commencing the operation to release the spear. After the hold on the fish is broken, rotate to the right while pulling the string. The left-hand wickers on the spear slips or grapple should then screw the tool off the fish.

A circulation sub should be installed in the fishing assembly when smaller spears are used.

#### Procedure to Engage and Pull the Fish

To engage and pull the fish:

1. Circulate with the spear a few feet above the top of the fish. Once clean, cut the pump back (stop pump if pack-off is installed) and lower the spear into the fish.
2. Rotate the string to turn the tool one half to one full rotation to the left to set the spear. Left-hand rotation turns the mandrel of the tool through the grapple, setting it in its engaging position.
3. The fish can now be pulled as this should wedge the grapple into a positive engagement on the fish.

#### Procedure to Release the Fish

To release the fish:

Bump down (maximum allowable) weight of the fishing string. This breaks the engagement. Rotate two or three turns to the right and pick up the string until the spear is clear of the fish.

1. Right-hand rotation moves the mandrel up through the grapple forcing the grapple down against the release ring and puts the spear in the release position.
2. If the spear does not release, bump down while simultaneously rotating to the right and picking up the string until the spear is clear of the fish.
3. If the spear still does not come free, use of the surface jar should be considered depending on the depth of the top of fish.

### 12.6.6 Washover Strings

Washover strings may be used in the following situations:

- Where the formation has bridged-off and stuck the string.
- Where the string has become cemented in the hole.
- Dressing the top of the fish for latching on with an overshot

## General Considerations

The considerations below should be considered when preparing to use a washover string:

Preparation	General Guidelines
Shoe Selection	<ul style="list-style-type: none"> <li>Inside casing: hard facing only on the bottom and inside the shoe so that it does not cut on the outside diameter</li> <li>Open hole: hard facing can be on the inside and outside. Washing over in open hole should only be considered in exceptional circumstances</li> </ul>
Safety Joint and Drive Sub	<ul style="list-style-type: none"> <li>A safety joint and drive sub should be installed above the washover string to release the string if the washover string becomes stuck</li> </ul>
Number of Joints	<ul style="list-style-type: none"> <li>Number of joints run depending on the hole inclination and Dog Leg Severity</li> </ul>
Rotation	<ul style="list-style-type: none"> <li>Low RPM and weight should be used during washovers to reduce the possibility of splitting or flaring the shoe</li> </ul>

**Table 82. Preparation of Washover String**

Reciprocate pipe periodically in order to monitor torque build-up and string resistance. The washover string should be kept in motion as much as possible to prevent sticking.

A junk sub should be installed above the washover string if stabiliser blades are to be washed over.

The mud may be “slicked up” by adding lubricants or changing mud rheology, allowing for hole cleaning requirements..

### 12.6.7 Junk Retrievers

The two main types of junk retrievers used in fishing operations are the coring type basket and the reverse circulation junk basket or jet retriever. These are described in the table below.

Junk Basket Type	Description
Coring Type	<p>The coring type basket cuts a short core. As the core is being cut, junk is forced into the barrel of the tool.</p> <p>When enough penetration has been made to retrieve the fish, stop rotation and circulation and break the core.</p> <p>The upper and lower catchers of the tool maintain the core in place. POOH.</p>
Reverse Circulation	<p>Mud is diverted through jets by pumping a drop ball from surface causing the mud to be directed outward and downward from the body of the tool.</p> <p>Once the junk has been washed into the tool, catch fingers prevent it from dropping out.</p> <p>This type of junk basket may also be available with a coring shoe.</p>

**Table 83. Junk Basket Types.**

### 12.6.8 Miscellaneous Fishing Tools

The following miscellaneous fishing tools may be used.

Tool	Usage
Lead Impression Blocks	<ul style="list-style-type: none"> <li>Used if additional information regarding the top of the fish is needed</li> </ul>
Rope Spears	<ul style="list-style-type: none"> <li>Used to fish broken wireline from the hole</li> <li>A stop ring should always be run with a rope spear to prevent the spear from passing too far past the top of the wire rope</li> <li>After the tool has entered the wire rope, it should be rotated one or two turns only and overpull should be taken until the line comes free or breaks at the weak point</li> </ul>
Taper Taps and Die Collars	<ul style="list-style-type: none"> <li>These tools are difficult to release once engaged and therefore a safety joint and jar must be run with them. They should generally only be run as a last resort. External fishing tools and spears should be run first</li> <li>Taper taps and die collars must only be run by experienced personnel and extreme care must be exercised when they are used to avoid sticking the entire string</li> </ul>
Junk Subs	<ul style="list-style-type: none"> <li>Consideration should be given to running junk subs in drilling or milling strings when required</li> </ul>

**Table 84. Miscellaneous Fishing Tools and their Use.**

## 12.7 CURING LOST CIRCULATION

Lost circulation or lost returns are the loss, to the formation, of either drilling fluids or cement slurry while drilling or completing wells.

The recommended lost circulation material (LCM) that may be used across reservoirs and other formations without causing formation damage is normally Enerseal super fine or its equivalent, Sandseal. Quantities shall be determined on site, and returns are carefully monitored. If formation damage is not a concern other types of LCM (eg. Mica) may be used.

LCM can be used either in concentrated slugs, to deal with more severe losses or as a general drilling fluid treatment to treat seepage/minor losses. When seepage losses increase to more than 20 bbls/hour, an LCM pill may be required to provide more effective prevention than can be achieved by circulating LCM in the drilling fluid.

The generic procedure for the preparation and application of an LCM pill is as follows:

1. Mix an LCM pill in the slugging pit using the recommended LCM material (or alternative approved material where applicable). The actual concentration will be dependent upon the magnitude of the losses and the size of the jets in the drilling bit.
2. Spot the LCM pill on bottom.
3. Pull the bit above the loss zone and the top of the LCM pill.
4. Observe the well for one hour, keeping the hole full as required.
5. Gradually commence circulation and attempt to regain full returns.

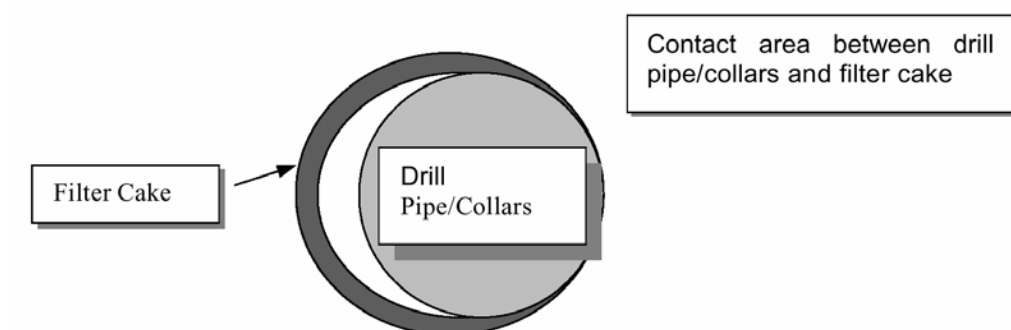


## 12.8 DIFFERENTIAL STICKING

Differential sticking of drill pipe/collars occurs when the hydrostatic fluid pressure in a wellbore exceeds the formation pore pressure across the interval where the pipe is stationary.

In permeable formations, the drill pipe/collars block the flow of fluid from the wellbore into the formation. This flow, which can be considerable, usually results in the build up of a thick filter cake across the permeable zone. When the drill pipe/collars have been left stationary, such as during connections or when a survey is taken, the surface of the BHA along with the sealing effect of the filter cake forms an effective block reducing fluid loss to the formation.

Depending on the length of the blocked area and the differential pressure between the borehole and formation, this blockage can cause extremely high forces to build up against the drill pipe/collars resulting in the BHA becoming differentially stuck as shown in Figure 30.



**Figure 30. Illustration of Differential Sticking**

Full circulation and no up/down mobility or rotary freedom, other than pipe stretch and Torque, are primary indications of differential sticking.

For differential sticking to occur, the following two conditions must exist:

- The hydrostatic pressure of the mud exceeds the pressure of the adjacent formation.
- The formation is porous and permeable (usually sandstone) at the point where the pipe is stuck.

The following conditions can result in differentially stuck pipe:

- High overbalance pressures
- Thick filter cakes
- High-solids mud
- High-density mud
- Significant pressure depletion of reservoirs

When filter cake builds-up on the formation, it increases the contact area between the wellbore and the drill pipe. Excessive drill solids and a high fluid loss increase filter-cake thickness and the coefficient of friction, making it difficult to pull or jar the drill pipe free.

If the pipe does become stuck, every effort should be made to free it immediately. The probability of freeing stuck pipe decreases rapidly with time. Early identification of the sticking mechanism is crucial, since each cause must be solved with a different measure. An incorrect solution can easily make it worse. Typically an evaluation of the events leading up to the stuck pipe incident usually indicates the cause which can lead to proper corrective measures.

Depending on the area and the severity of the pressure depletion, one or several of the following methods may reduce the chance of stuck pipe across the depleted zone. All of the conditions associated with differentially stuck pipe cannot be eliminated, consequently no unique solution exists that can be applied in all areas.

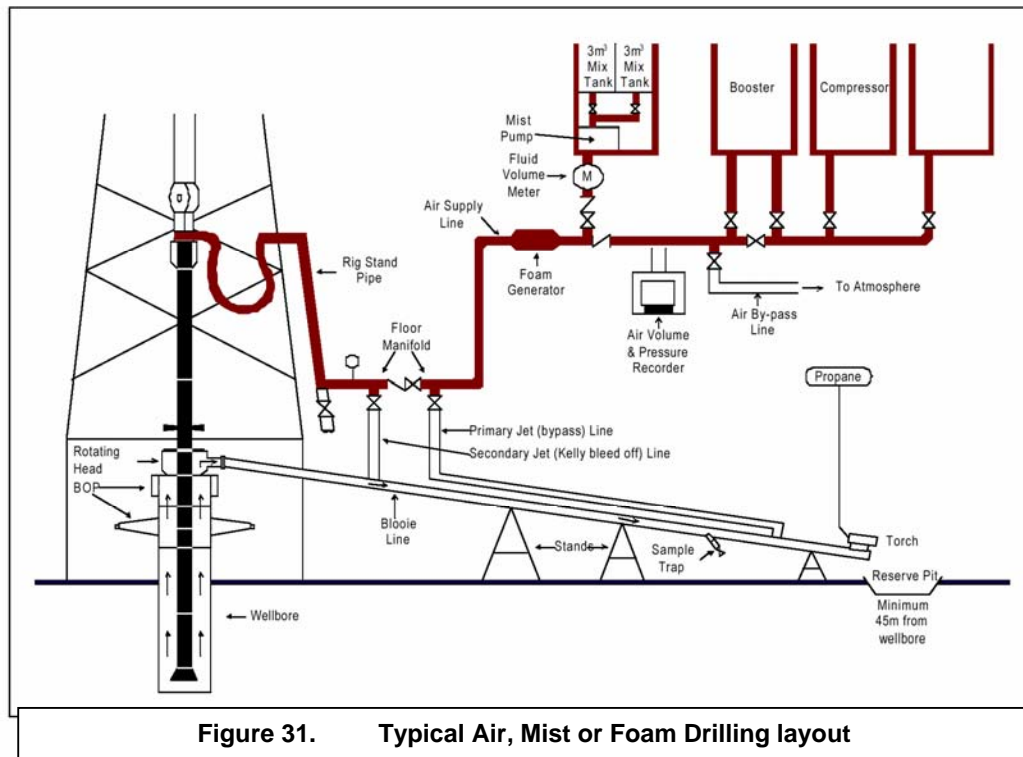
### 12.8.1 Preventative Measures

While drilling through areas of known pressure depletion:

1. Educate drillers so they are aware of what immediate action is required in the event of tight hole/differential sticking problems.
2. In open hole keep the pipe moving at all times.
  - Reciprocating is the preferred method as it allows you to monitor overpulls. If possible, always begin pipe motion in a downward direction.
  - While making connections minimise the time in which the drill pipe is stationary. (Rotate pipe as long as possible).
  - During well control situations, if possible close annular BOP's and reciprocate drill pipe. Obtain approval to close annular BOP's from rig contractor prior to spud.
3. Minimise the contact area of the BHA in the wellbore.
  - Use spiral drill collars and minimise unstabilised sections of the BHA. Spiral drill collars have a smaller contact area with the wall of the hole and allow fluid passage and equalising of hydrostatic fluid pressure.
  - If hole drag is not a problem, consider using under-gauge stabilisers on drill collars to keep them away from the borehole wall. The use of a packed hole assembly can reduce the number of situations that result in differential sticking by holding the drill string off the wall of the hole. Another unrelated benefit to running bit stabilising assemblies is the prevention of sudden hole angle changes (offsets and doglegs), which can lead to key seats.
  - Only run the minimum length of drill collars to provide the required bit weight. Use heavy weight drill pipe instead of long sections of unstabilised drill collars.
4. Do not program any non-essential surveys. However if surveys are required, they should be dropped prior to POOH rather than run on wireline.
5. If known depleted reservoirs have to be drilled through to reach and evaluate undepleted reservoirs, casing off of the depleted reservoirs may be necessary to avoid acute drilling problems.

## 12.9 AIR DRILLING

Air may be the circulating medium for drilling some wells in GSLM areas of operation.



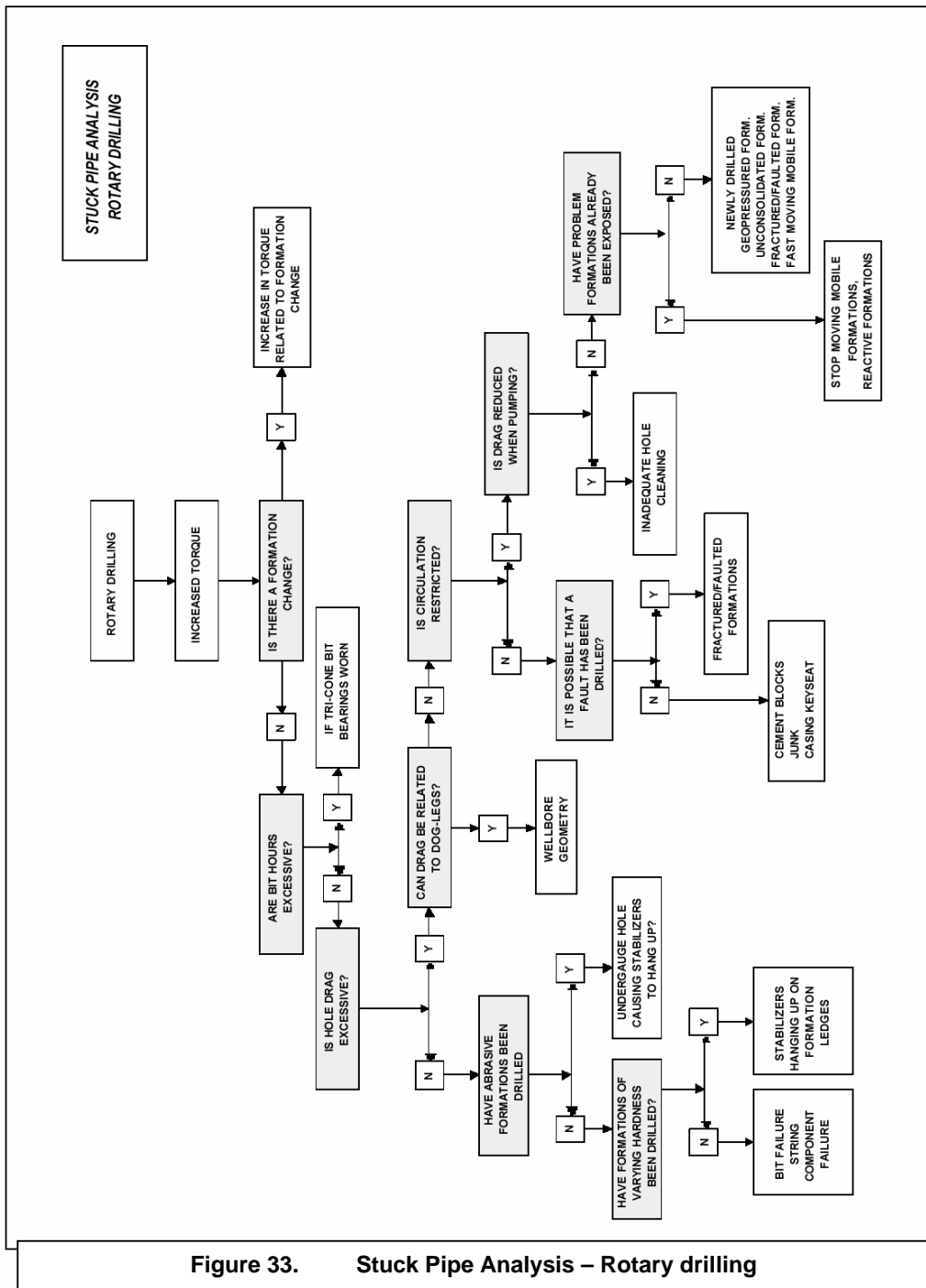
The following general guidelines shall be adhered to whilst air drilling:

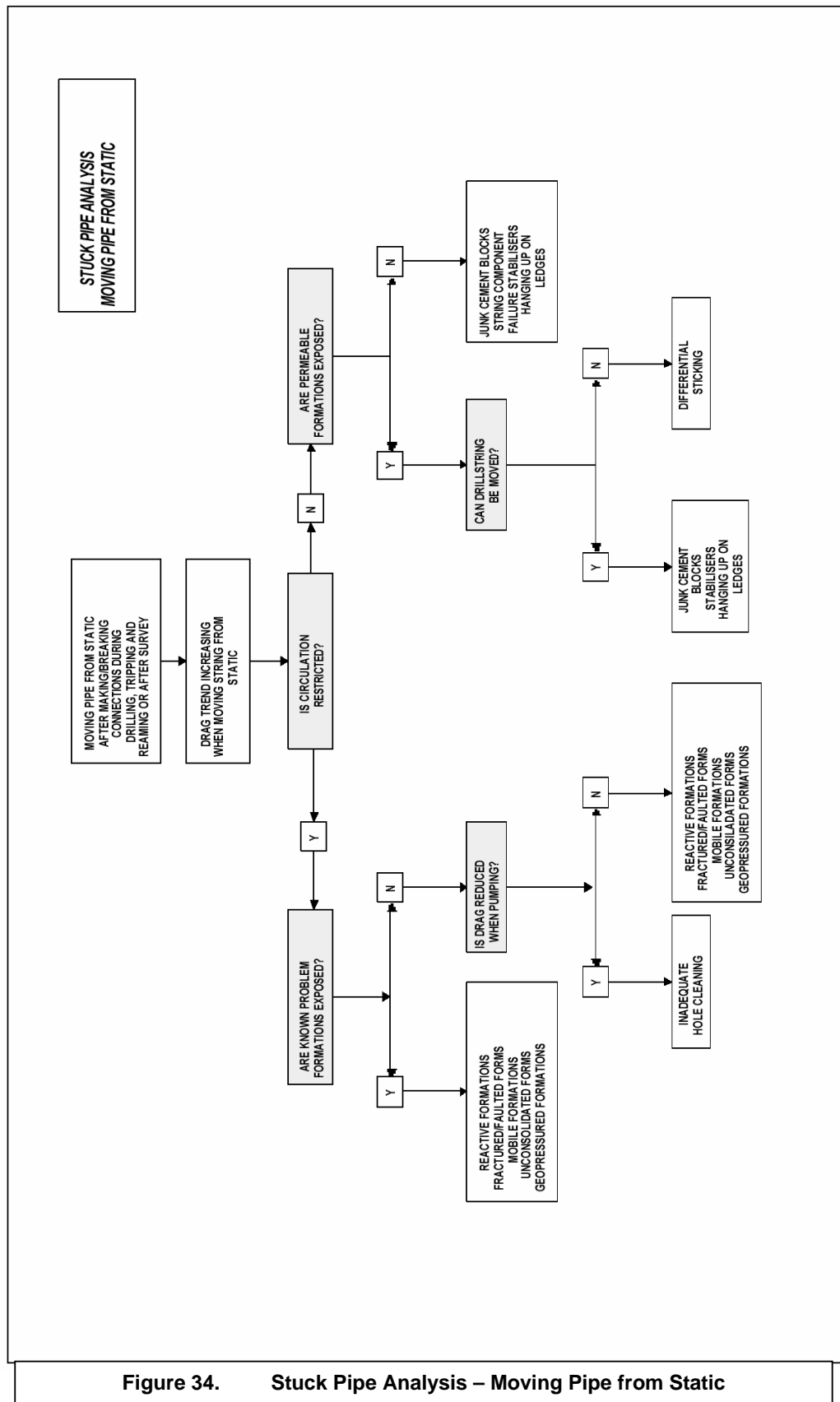
- A chart type pressure recorder is critical to monitor air pressure effectively. The recorder should be immediately downstream of the air compressors.
- It is essential to have air circulating around the bit before starting drilling. This prevents initial cuttings build-up which is a significant cause of stuck pipe, and prolongs bit life by cooling bearings and cleaning cuttings from the bit. Drilling should not begin after a connection until one of these two conditions is met.
- In order to prevent the drill string from becoming stuck as a result of pulling into and packing dry drill cuttings, never pull on the string without air circulation.
- No upper air volume limit has been established for air drilling. However, a frequent cause of failure while drilling with air is insufficient air volume to clean the hole efficiently under a varied range of drilling conditions. The air drilling contractor shall provide field data to establish the optimum values.
- Drill cuttings not removed fall back and bridge when connections are made. Should this occur, options to overcome the problem are:
  - Increase air volume.
  - Always blow the hole until the air and mist returns are clean, before making connections.

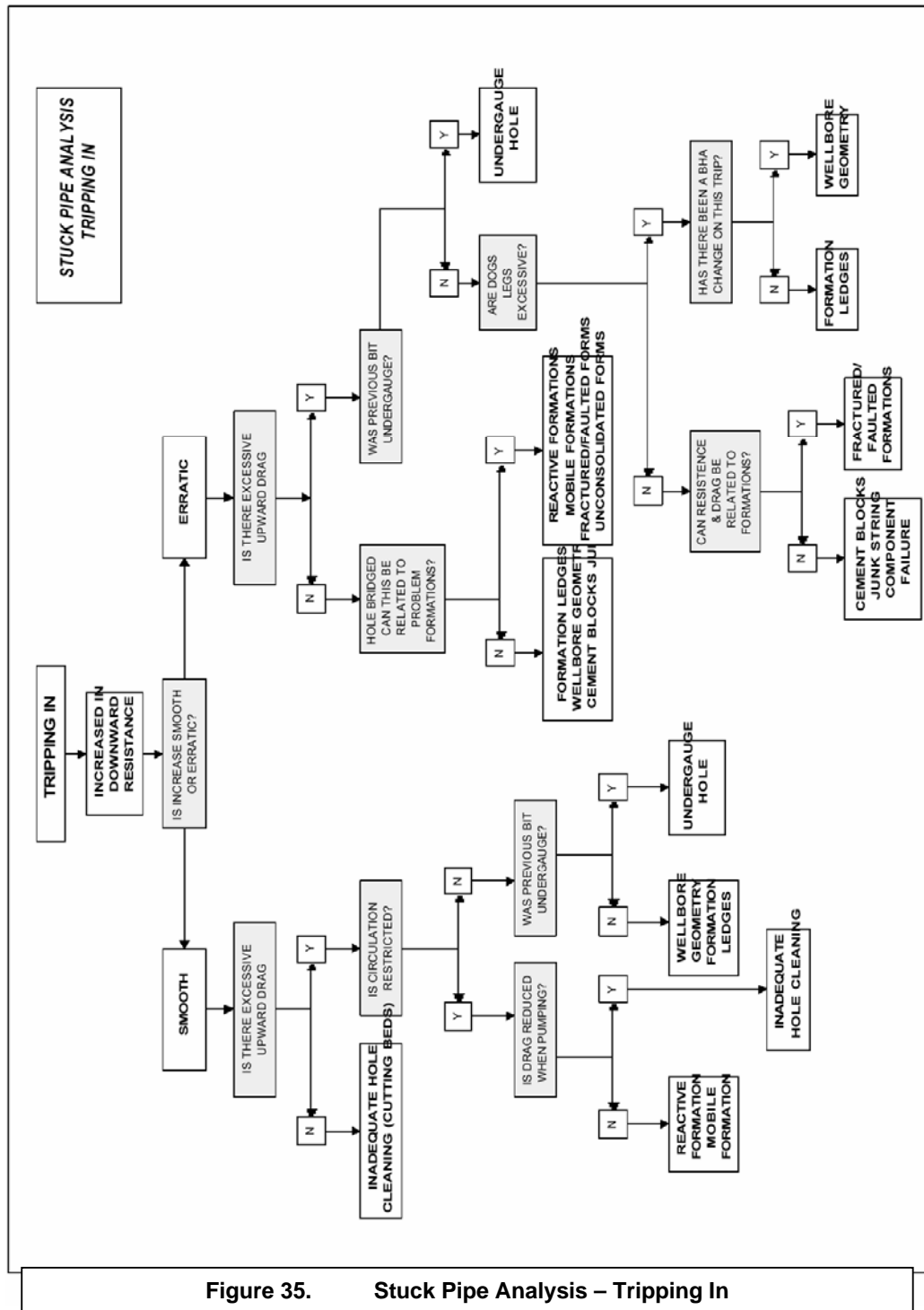
Appendix I: Stuck Pipe Analysis - Identifying Causes

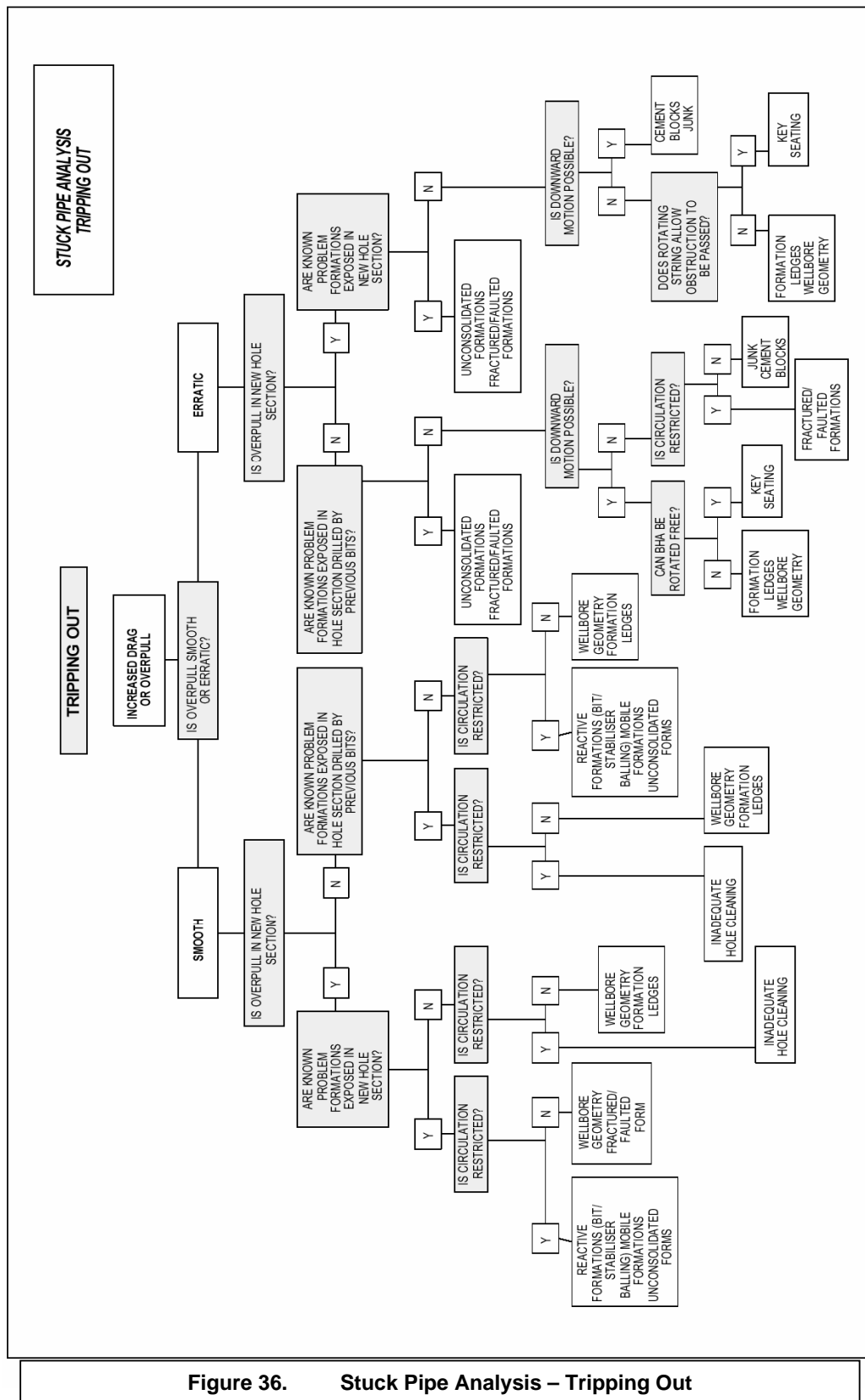


Figure 32. Stuck pipe Analysis – Identifying Causes

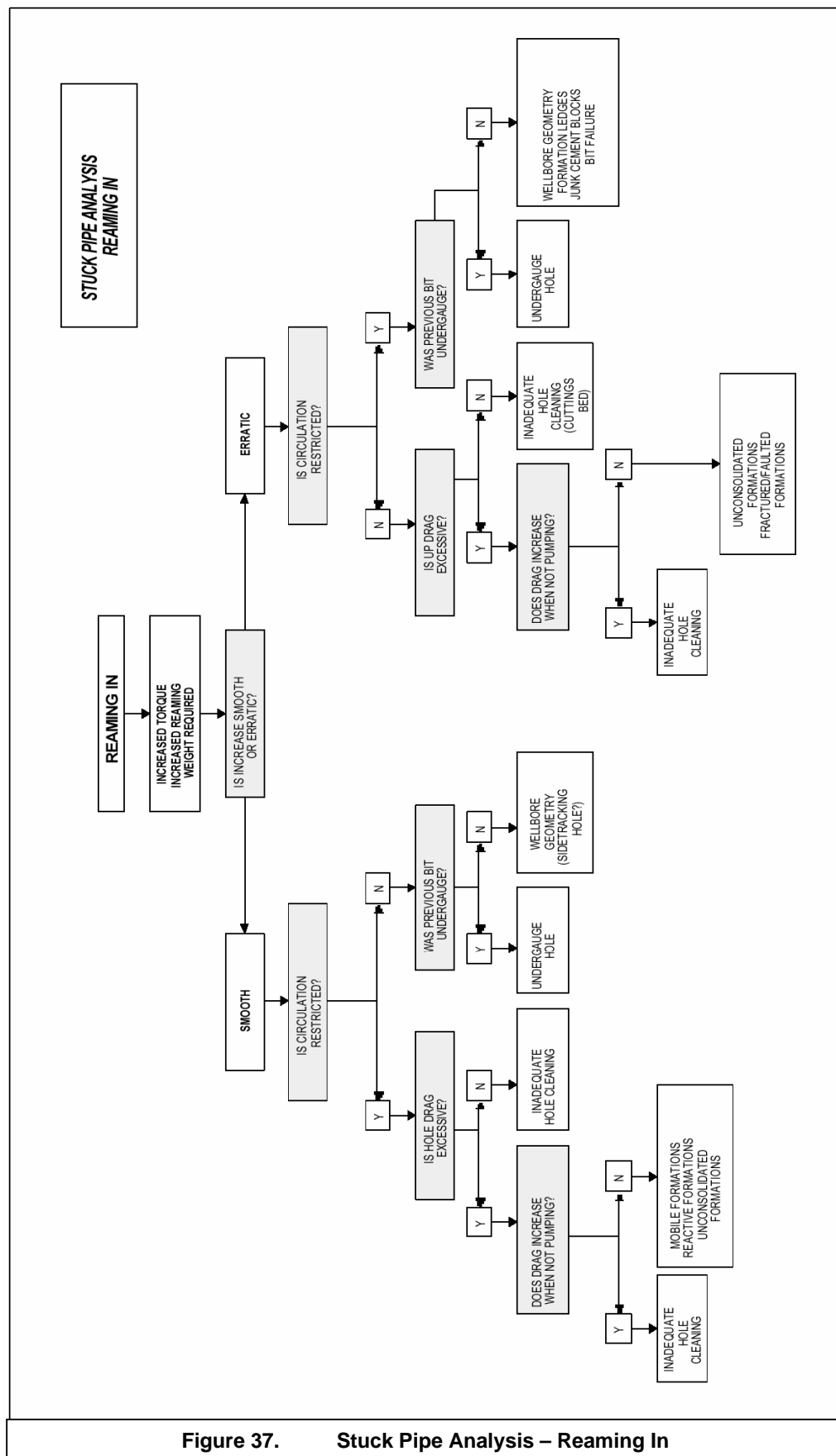


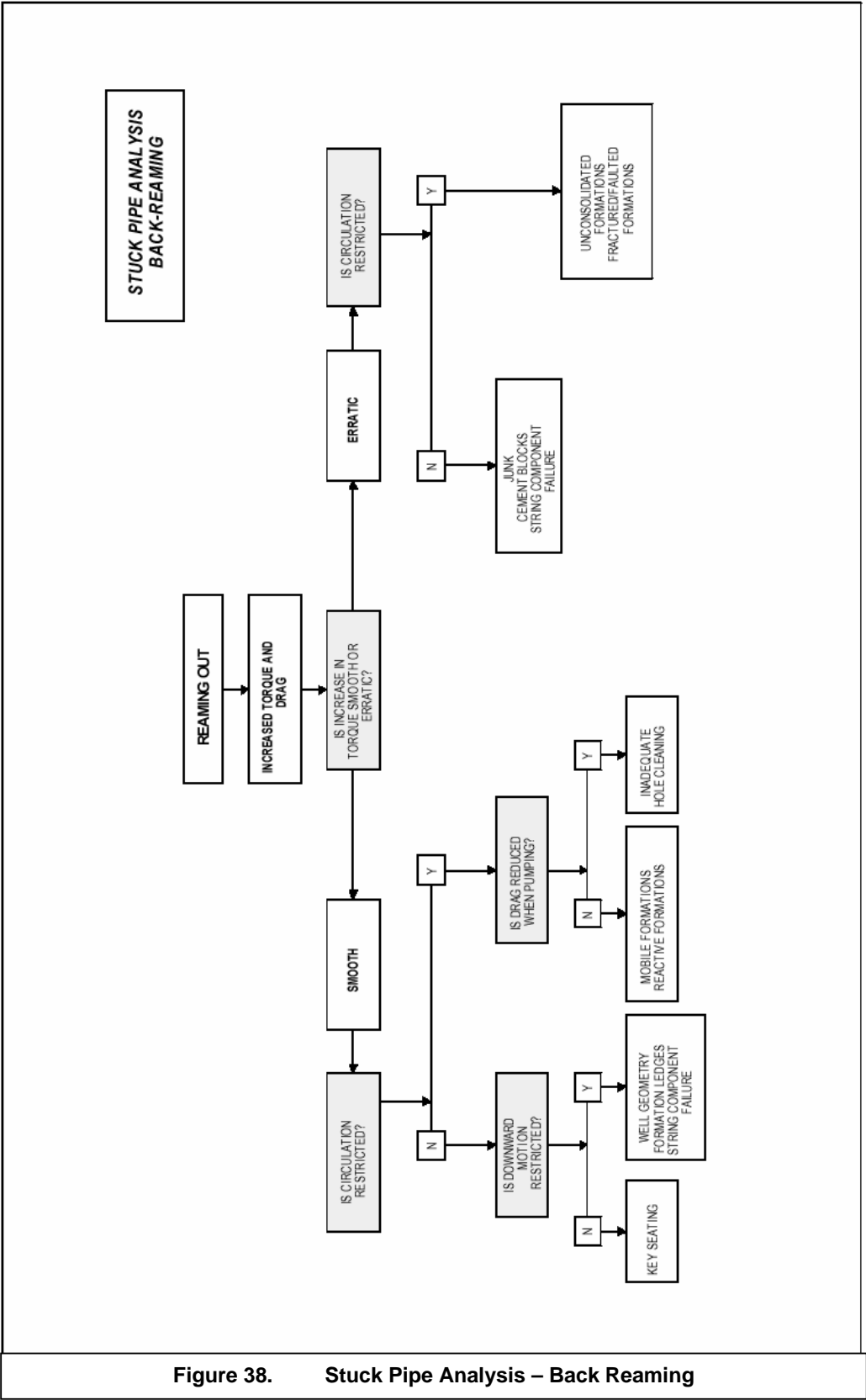


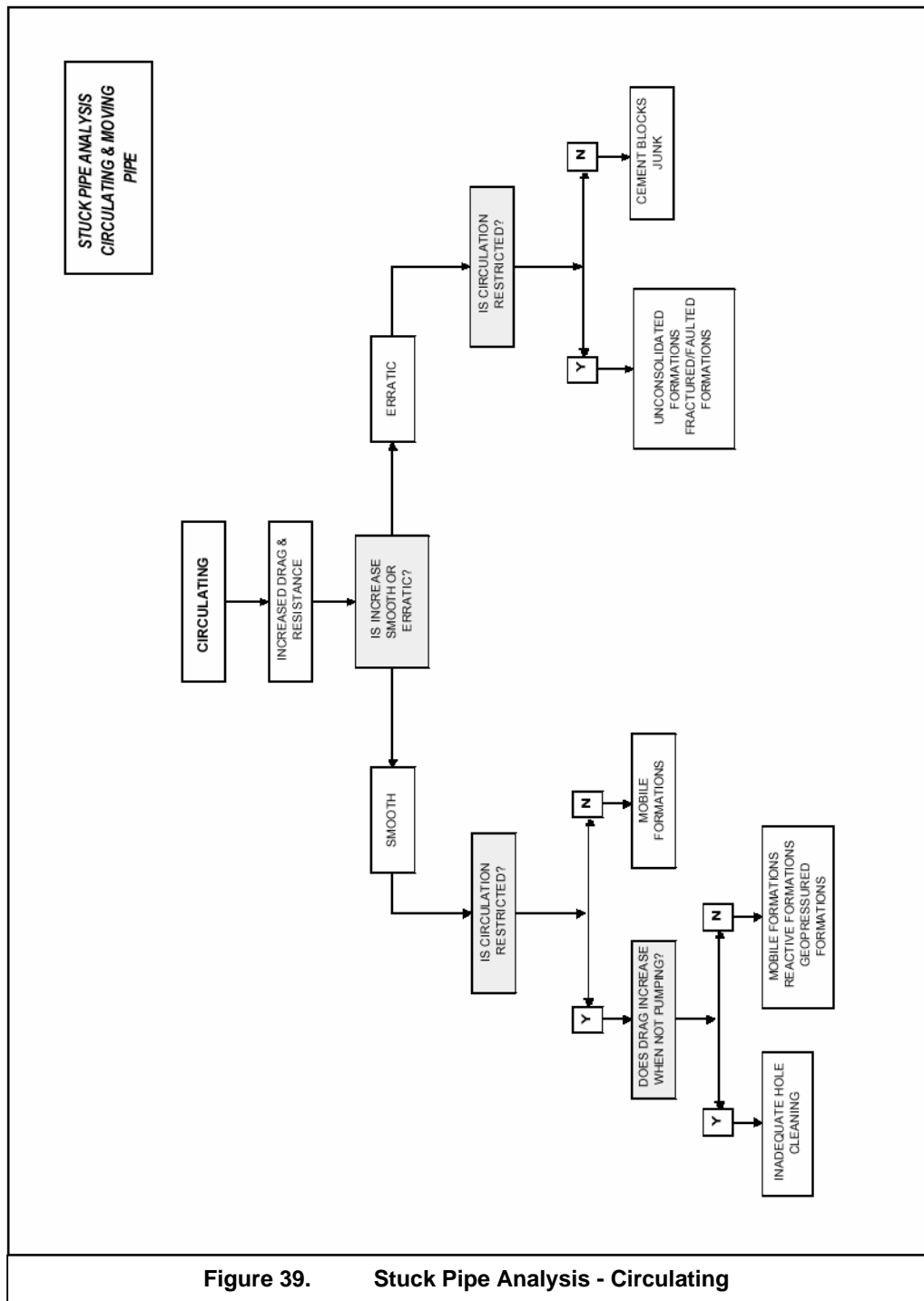


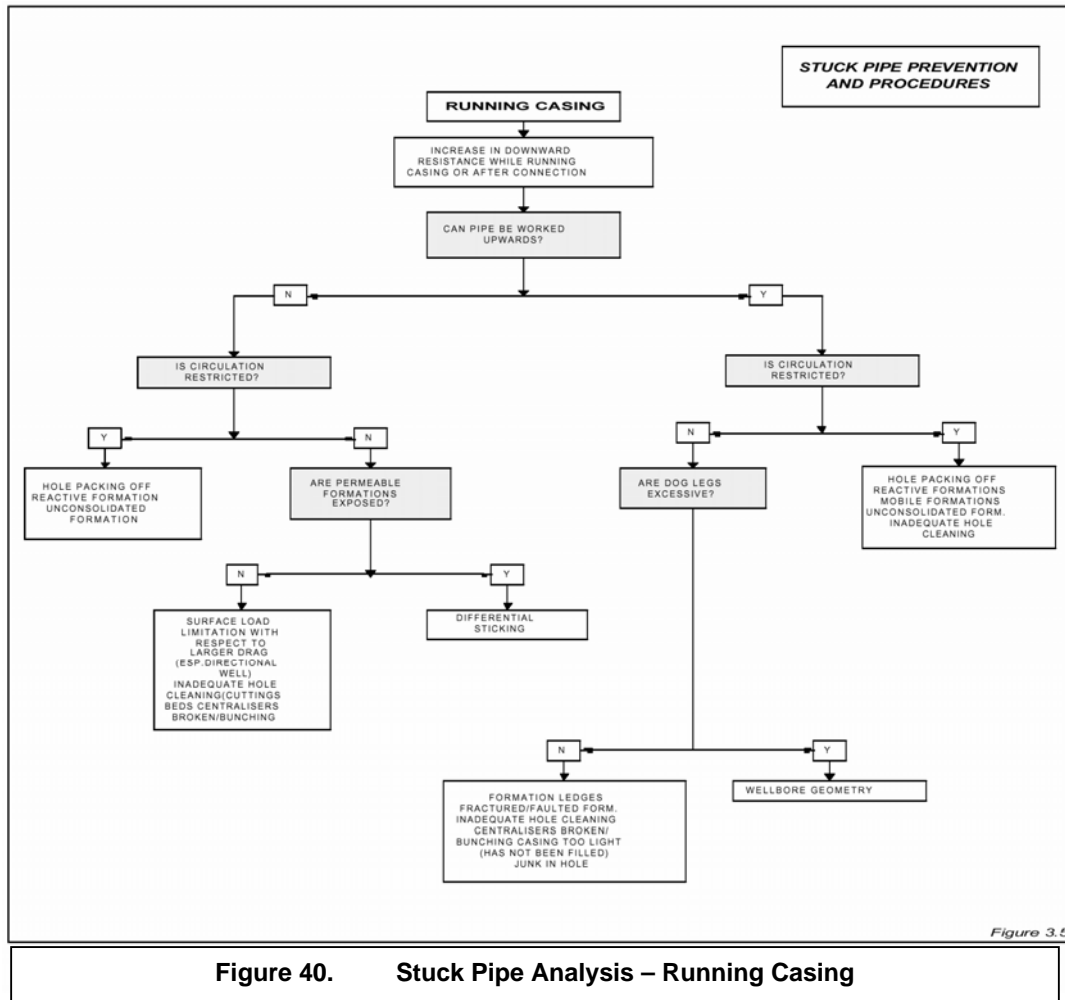












## **CHAPTER 13 HAZARDOUS MATERIALS HANDLING**

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### 13.1 OBJECTIVES

The primary objectives of these procedures for hazardous materials handling during drilling operations are to ensure that:

- All personnel involved in the supervision of, or direct handling of hazardous materials, are fully aware of their responsibilities and comply with Government regulations and GSLM policies.
- The primary areas of risk to personnel in the direct and indirect handling of hazardous materials are known and understood.
- Adequate measures shall be taken to prevent or minimise risks associated with handling hazardous materials.



Occupational Health, Safety and Welfare Act 1986, Explosives, Sections 5.12.25 to 5.12.51

### 13.2 RESPONSIBILITIES

Responsibilities for the receipt, storage, maintenance and handling of hazardous materials and equipment at the wellsite are summarised in the table below.

Task	Performed by	Verified by
Authorisation of receipt of materials at wellsite	DSV	DSV
Storage of drilling fluids chemicals	Drilling Fluids Contractor	DSV
Maintenance and handling of drilling fluids chemicals	Drilling Fluids Contractor	DSV
Receipt, storage, maintenance and handling of radioactive materials and equipment	Electric Logging Contractor	DSV
Receipt, storage, maintenance and handling of explosives	Electric Logging Contractor	DSV
Receipt, storage, maintenance and handling of hazardous chemicals	Drilling Fluids / Electric Logging Contractors	DSV
Receipt, storage, maintenance and handling of other contractor materials	Relevant Contractor(s)	DSV

**Table 85. Responsibilities for Receipt, Storage and Handling of Materials at Wellsite**

### 13.3 RADIATION

The following section describes the principles and guidelines for the use of radioactive materials and the hazards associated with their handling.

#### 13.3.1 Radiation Principles and Guidelines

The primary reference document for the use of radioactive sources for wellsite operations is the Schlumberger Radiation Control Manual, or alternative Electric logging Contractor's equivalent.

Operations involving the use of radioactive materials shall only be performed by fully trained and competent personnel. These personnel will follow the correct operational and safety procedures, in order to minimise the hazards and avoid significant risk to personnel and the environment.

Certain operations (e.g. radioactive tracer jobs) involve the use of unshielded radioactive fluids, and in such operations the risk of contamination co-exists with that of irradiation. For these operations, additional, special procedures shall be implemented to ensure safety.



Schlumberger Radiation Control Manual (or alternate Logging Contractor's equivalent)

#### 13.3.2 Radiation Hazards

Ionising radiation cannot be detected directly by humans. Biological effects of radiation are:

- Massive instantaneous doses kill in a short time.
- The same total doses over a longer period can cause cancer and eventual death.

The above effects require that protection from ionising radiation includes the control of the total cumulative doses received, as well as checks on short term exposure at high dose rates.

All workers who may be exposed to occupational radiation shall be controlled and protected by a monitoring system which records their doses. The DSV shall ensure that the ALARPP system (As Low As reasonably Possible) shall be applied in order to provide the most effective control of radiation.

- Minimise field strength through shielding of sources and maintaining maximum distance.
- Minimise time of exposure.
- Set strict limits of acceptable dosage for various categories of workers who may be exposed to radiation, and monitor their cumulative doses.
- Strictly control access of all personnel to areas subject to radiation.

All Wireline Company personnel must wear approved film badges or dosimeters when handling radioactive sources.

### **13.3.2.1      Radiation Hazard Controls**

The DSV shall ensure that only specifically trained and certified personnel are permitted to work with radioactive materials. At the wellsite this is usually the Electric Logging Contractor's engineer and other suitably qualified members of the logging crew. No unqualified person is permitted to work on, approach or in any way interfere with radioactive tools or protective radioactive container.

Exposure to ionising radiation is minimised by effective shielding. Different types of radiation have different shielding requirements. This is stated on the documentation arriving at the wellsite with the hazardous goods. It is the responsibility of the DSV to ensure all such documentation accompanies the goods.

Emergency shielding from gamma rays shall be achieved by the use of sacks of barite weighting material (i.e. when the source cannot be readily detached from the logging tool). Emergency shielding from neutron sources shall be achieved by immersing the source in a 55 gal drum filled with drilling fluid.

### **13.3.2.2      Storage and Control of Radioactive Materials**

It is the responsibility of the DSV to ensure the correct storage of radioactive materials at the wellsite. Permanent storage facilities shall be provided for the storage of radioactive material.

The Electric Logging Contractor shall provide a dedicated radioactive storage container, which shall be used and controlled at the location as follows:

- The permanent store shall be located in a marked area on the location, away from normal personnel access, where the radiation level shall not exceed 1.0  $\mu\text{Sv}/\text{hour}$  at the perimeter of the marked out area.
- The storage facility shall be secured with a padlock, controlled by the radiation qualified personnel.
- The standard trefoil radioactive warning sign shall be exhibited on the storage container.

### **13.3.2.3      Transport of Radioactive Sources**

The Electric Logging Contractor shall be responsible for transporting radioactive materials in appropriate vehicles and in the correct manner to and from the wellsite. Should any source be lost or damaged in transit, it shall be the contractor's responsibility to notify the DSV and the relevant authorities and make the necessary arrangements for recovery.



## 13.4 EXPLOSIVES

The following section describes the handling, storage, transport and basic safety requirements for explosives on the wellsite

### 13.4.1 Explosives used in Drilling Operations

Chemical explosives used in wireline activities are divided into two main categories: Low and High Explosives. The latter are subdivided into primary (1°) and secondary (2°) explosives. These are described in the table below.

Explosive		Detonated by	Handling and Storage
<b>Deflagrating or Low Explosives</b>		Exposure to heat or flame	<ul style="list-style-type: none"> <li>Suitable for sample takers and bullet guns</li> <li>May be transported with secondary (2°) explosives but not with primary (1°) explosives</li> </ul>
<b>Detonating or High Explosives</b>	1°	Hot wire, flame or percussion	<ul style="list-style-type: none"> <li>Extremely sensitive to stray electrical current, electromagnetic transmission (microwaves, radio transmissions), friction and impact. Can be detonated by any small disturbances.</li> <li>Store in properly grounded containers, handle only by properly trained personnel at wellsite</li> </ul>
	2°	High energy shock wave provided by High Explosives	<ul style="list-style-type: none"> <li>Extremely insensitive. Relatively safe to handle</li> </ul>

**Table 86. Categories of Explosives used in Drilling Operations**

### 13.4.2 Transportation of Explosives

Road transport of explosives is controlled by the Electric Logging contractor. The contractor shall be responsible for obtaining all necessary permits to import, store and transport explosives. The following must be adhered to:

- Explosives shall be securely stored and held in the vehicle, in wooden lined containers. Detonators shall never be transported in the same containers as explosives. Up to 25 Kg of explosives may be carried in the same vehicle as detonators, provided these are contained in an adequate, grounded separate container.
- Explosives transport containers shall only contain designated explosives.
- Loaded perforating guns shall be securely fastened to the floor of the vehicle.
- The vehicle shall carry prominent explosives warning notices in compliance with legislation.
- Smoking is strictly prohibited in and within the vicinity of a vehicle carrying explosives.
- Vehicles transporting explosives shall carry a minimum of two persons, one of whom shall be trained and certified in the handling of explosives.
- Vehicles designated for transport of explosives should be diesel powered.
- Vehicle refuelling should be avoided wherever possible. If unavoidable, maximum care should be exercised while refuelling.

- All road journeys shall be conducted using a suitable journey management control, which requires effective liaison between the Electric Wireline Logging Contractor's despatch office and the wellsite, from departure until arrival.

It is the responsibility of the DSV to ensure that the above guidelines are met, reporting any non conformance to the DM.

### **13.4.3 Storage and Handling of Explosives**

The electric Wireline Logging Contractor shall provide a dedicated explosives storage container which shall be used and controlled on location as follows:

- The permanent store shall be located in a marked area on the location, away from normal personnel access, and at a safe distance from exhausts, welding equipment and any other source of ignition.
- The storage facility shall be secured with a padlock, controlled by the logging operator.
- Access shall be strictly subject to a Permit to Work system.

The logging operator shall be the sole person permitted access to the wellsite explosives store. The operator and the crew shall be the only personnel permitted to handle explosives at the wellsite. Storage and handling of the different types of explosives must be performed in accordance with the standards given in the table in section 13.4.1. The Logging Contractor shall ensure all necessary certificates of competence are obtained for each logging crew member, which shall be available on request.

The DSV shall ensure that the above storage and handling procedures are adhered to.

#### **13.4.3.1 Handling and Storage of Primary Explosives**

Primary explosives shall at all times be kept in a separately dedicated storage container, in accordance with the controls above. The segregation from other explosives shall be such that accidental detonation of primary high explosives cannot induce high order detonation of any other explosives in the same storage facility

Under no circumstances shall explosive devices fitted with primary high explosives be stored, even temporarily, at the wellsite. If any delay in the program requires cessation of operations after guns have been armed, they must be disarmed by the contractor's wireline engineer prior to storage or transportation.

The DSV shall ensure that the above procedures are adhered to.

### **13.4.4 Basic Wellsite Safety of Explosives**

The DSV shall ensure that the following precautions are adhered to at the wellsite during drilling operations:

- a) The loading and unloading of secondary high explosives (shaped charges, detonators) in perforating guns, or other explosive devices, shall be performed by the contractors personnel, trained and licensed on logging operations and explosives handling.

- b) The arming of any explosive device, with a primary high explosive detonator, shall only be performed by the Logging Contractor's engineer, immediately before introducing the device into the wellbore. Make-up and arming of explosive devices shall be performed in a designated area surrounded by a taped area.
- c) During all operations involving explosives, the number of persons present must be kept to a minimum. All personnel not directly involved in the operation shall be excluded from the area of operation, and remain at a safe distance.
- d) Underbalanced perforating or perforating in any well requiring pressure control equipment shall be avoided in the hours of darkness, due to the dangers of not detecting a broken strand in the wireline.
- e) Adequate precautions should be kept to prevent accidental discharge of electric blasting caps and/or ignitors from currents induced by galvanic currents, radio transmitters etc.
- f) Helicopter landing is not permitted whilst the Logging Contractor is handling live explosives. If necessary the explosives operations shall be halted until the helicopter has shut down or departed.
- g) Handling of explosives at night is only to be allowed if sufficient lighting is available. Smoking, open fires and naked lights of any kind (exposed incandescent material e.g soldering irons, etc.) are strictly prohibited within the safe distance of explosives and shooting equipment.
- h) Electrically initiated detonators are extremely sensitive to electrical energy, both in the form of stray currents and direct electromagnetic radiation. Potential sources of such currents and EM radiation, and the precautions to be taken are tabulated below.

Electrical Energy	Precaution
Faulty equipment/ incorrectly earthed electric generators	Faulty equipment wiring can set off guns at surface. The location and rig wiring shall be checked for damaged insulation, loose wires or hanging cables. Attention shall be given to the earthing of all electrical equipment.
Impressed current cathodic protection systems	All flowline/casing cathodic protection devices shall be switched off for the duration of the operation.
Welding equipment	Electric Arc Welding can cause unacceptable voltage differences or dangerous EMM radiation levels. All arc welding shall be stopped before electrical detonators are connected to guns, and remain shut down until the guns are fired, retrieved and inspected on surface.
Radio transmissions	All radio transmissions in the vicinity of the operation shall be suspended for the duration of the operation (See 'Radio Silence' below).
Static charge build-up of rig structure	No electrically detonated explosives shall be used during periods when threatened by electric storms

**Table 87. Precautions when Handling Explosives in the Vicinity of Electricity**

All non-essential electricity supplies and equipment which may cause stray currents shall be turned off during perforating operations. When connecting the electrical detonators to the guns and whenever the guns are less than 500 ft below surface, all non essential generators, including the generator of the logging unit, shall be stopped. AC rig generators may be kept operating if required for lighting and rig safety systems.

Prior to initiating any operation with electrically detonated explosive devices, the Logging Contractor's engineer shall connect a voltage monitor between the rig mass and wellhead (casing) to verify that stray currents have been eliminated.

### 13.4.5 Radio Silence

The DSV shall ensure that the radio silence procedures are enforced whenever operations involving the use of electro-explosive detonators are being carried out. These operations include; perforating, side wall sampling, formation interval testing, explosive backing-off (string shot), explosive cutting and setting of wireline set packers and bridge plugs. Radio shut-down requirements during operations with explosives apply within a 450 m (1500ft) radius of the wellhead.

Logging Operation		Making up or Rigging down and < 60 m (200') below Rotary Table	Explosives > 60 m (200') below Rotary Table	After inspection of retrieved tools and Before loading next, or after firing last charge (whilst still in hole)
<b>A</b>	Perforating, sidewall sampling, FITs (not RFTs), explosive backing-off, explosive cutting	Full radio shut-down Hand held radios and mobile phones collected by DSV	No restrictions	Hand held radios and mobile phones should not be re-issued/ returned.
<b>B</b>	Wireline set packers and bridge plugs	Hand held radios and mobile phones not allowed on rig floor, otherwise no restrictions	No restrictions	No restrictions

**Table 88. Radio Silence Procedures during Electric Logging Operations**

Receive-only radios can remain in operation during any of the operations listed in the table above. However the back-up UHF transmitter must be switched off while operations defined in 'A' (table above) are being carried out.

No operation defined in the table above shall be carried out during weather conditions which are likely to produce electrical discharges.

## 13.5 HAZARDOUS CHEMICALS

The following section describes the handling, storage and disposal of hazardous chemicals

### 13.5.1 Safety Awareness

Every chemical stored or used at the wellsite shall be supplied with a current Materials Safety Data Sheet (MSDS). These shall be filed by the rig toolpusher at the wellsite, and kept in the Toolpusher's office, accessible to all site personnel at all times. The Toolpusher shall ensure that copies of relevant MSDS are issued to each personnel assigned to handle any chemical. The Toolpusher shall also ensure that copies of all MSDS sheets are sent to the nearest Hospital if required.

The relevant health and safety data on drilling fluid chemicals is also summarised on plasticised notices (Safety data Sheets) provided by each Drilling Fluids Contractor, for prominent display on site.

For each product the MSDS includes:

- First Aid information (i.e. relating to swallowing, inhaling or contact with eyes or skin).
- Spills and disposal procedures.
- Personal protection procedures.
- Storage and transport procedures.
- Fire precautions.

### 13.5.2 Hazardous Chemicals Used

The following two categories of hazardous chemicals are typically used at the wellsite.

#### 13.5.2.1 Drilling and Completion Chemicals

Hazardous drilling and completion chemicals used at the wellsite are categorised as follows:

- PH adjusters.
- Bacteriacides.
- Corrosion inhibitors.
- Bromide Salts for heavy brines

Bromide Salts are not generally used in GSLM activities. However, the handling standards and procedures for hazardous chemicals apply equally to each category.

Not all drilling and completion fluid chemicals are classified as hazardous. However the majority of chemicals cause skin irritation as a minimum effect. All should be handled with care and knowledge, using appropriate levels of personal protective equipment, and in accordance with the relevant MSDS (also reference section 13.5.3).

**Note:** Of all hazardous drilling fluid chemicals, Caustic Soda (Sodium Hydroxide, NaOH) is the most widely used. Personnel handling Caustic Soda must be made aware that it takes only a small particle in the eye to cause permanent damage.

### 13.5.2.2 Other Wellsite Chemicals

Non drilling fluid chemicals used at the wellsite are normally supplied and controlled by the following contractors:

- Electric Wireline Logging Contractor
- Cementing Contractor
- Drilling Contractor
- Mud Logging Contractor

All chemicals should be supplied with MSS. The most significantly hazardous chemical in use is the chemical cutter used by the Wireline Logging contractor, which contains an extremely reactive and toxic chemical. Rigid controls in the methods of storage, handling and application must be in place to ensure that the hazard is fully controlled and presents minimum risk to personnel or the environment.

A copy of the Logging Contractor's Procedures Manual must be available in each logging unit. It is the responsibility of the DSV to ensure that all relevant documentation is available.



Chemical Cutters Procedures in the Schlumberger Procedures Manual, or alternate Logging Contractors equivalent document.

### 13.5.3 Hazardous Chemicals Handling

The DSV shall ensure that the following personal protective equipment are available at the wellsite and are used by all personnel handling chemicals. The MSDS should state the required protective clothing which may include one or all of the following items:

- Dust respirator
- Chemical safety goggles or glasses
- Face shield
- Hard hat
- Chemically resistant gloves and/or cotton gloves
- Long protective clothing
- Neoprene protective apron
- Impervious safety boots

It is the responsibility of all personnel to ensure they are familiar with the health and Safety data relevant to the chemical(s) they are handling, via the MSDS and the displayed Safety data sheets on site. They should also ensure that safety equipment in their work area ( i.e. eye flushes, body showers etc.) are present and functional.

The Safety data sheets (section 13.5.1) provide all necessary information on the treatment of chemical contact of the body.

Operations personnel who are trained and assigned as First Aiders on site, shall also be familiar with the required responses to chemical effects, and shall ensure that specified safety apparatus is available and functioning on site.

#### **13.5.4 Hazardous Chemicals Storage**

All chemicals shall be stored in a designated area on pallets, and sufficient water-resistant covers shall be available to protect them in case of rain.

Those chemicals classified as hazardous shall be stacked separately from other chemicals, in a bunded area, and shall have a secure warning notice describing the chemical type(s) and major hazard(s), situated prominently next to them. Protecting these chemicals from rain and floodwater and preventing access by local wildlife, shall be a primary requirement.

#### **13.5.5 Hazardous Chemicals Disposal**

The safe disposal methods for both waste chemicals and their empty containers are dependant on the type of chemical, and shall be carried out in accordance with the following:



Material Safety Data Sheet (MSDS) for each chemical.

**CHAPTER 14**  
**WELLHEAD INFORMATION**

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**14.1 OBJECTIVES**



The objective of Wellhead Information is to provide a schematic overview of, and appropriate vendor references to, GSLM wellhead equipment standards as applied to all wells. Reference should also be made to the schematics of wellhead standards for suspension and abandonment in Chapter 11 of this Manual.

## 14.2 RESPONSIBILITIES

As this Chapter primarily provides a description of wellhead equipment, very few responsibilities have been defined.

Task	Performed by	Verified by
Order wellhead equipment	DM	DM
Confirm wellhead equipment conforms to requirements of Drilling Program.	DSV	DM
Confirm all required wellhead equipment is on location.	DSV	DM
Callout wellhead technician (if required)	DSV/DM	DM

**Table 89. Responsibilities for Wellhead Equipment**

## 14.3 STANDARD WELLHEAD CONFIGURATIONS

The standard wellhead configurations listed below identify the required wellhead assemblies and pressure ratings for wells drilled in Tasmania.

### 14.3.1 Conventional Wells

Casing Scheme	Pressure Rating
13 3/8" x 9 5/8" x 7"	3000 psi, 5000 psi
9 5/8" x 7"	3000 psi, 5000 psi

**Table 90. Standard Wellhead Configurations for Conventional and Downsized Wells**

GSLM will utilise API rated wellhead equipment, specified for the service, supplied by recognised wellhead manufacturers, and where possible fabricated and supported by locally based companies (e.g. Wood Group Pressure Control Australia Pty. Ltd, Cameron Australasia Pty. Ltd.). All wellhead equipment will be installed, operated and maintained as per the suppliers documented procedures. The wellhead supplier will supply technical support.