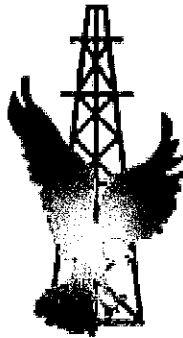


Section 8: Drilling Operations Manual

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Great South Land Minerals Limited

Great South Land Minerals Limited ABN 54 068 650 386

DRILLING OPERATIONS MANUAL

Revision Number	Revision Date	Revised Section	Revision Details	Revised By
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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

AC	Alternating Current	AHD	Along Hole Depth
API	American Petroleum Institute	BHA	Bottom Hole Assembly
Bbls	Barrels	bpm	Barrels per Minute
BOP	Blowout Preventer	CCL	Casing Collar Locator
BUR	Build-up Rate	cmt	Cement
CBL	Cement Bond Log	CET	Cement Evaluation Tool
Cu	Cubic		
DC	Drill Collar	DDE	Directional Drilling Engineer
DDR	Daily Drilling Report	DE	Drilling Engineer
DOM	Drilling Operations Manual	DP	Drill Pipe
DSV	Drilling Supervisor	DST	Drill Stem Test
E & D	Exploration and Development	ECD	Equivalent Circulating Density
EMW	Equivalent Mud Weight	EOB	End of Build-up
FIT	Formation Integrity Test	FPIT	Free Point Indicator Tool
ft	Feet	GSLM	Great South Land Minerals
gal	Gallon	GLG	Geologist
gpm	Gallons per Minute	GR	Gamma ray
HSWE	Health, Safety, Welfare and Environment	ht	Height
HTB	High Temperature Blend	HWDP	Heavy Weight Drill Pipe
IADC	International Association of Drilling Contractors	ID	Inside Diameter
IF	Internal Flush		
KOP	Kick-off Point	KB	Kelly Bushing
LCM	Lost Circulation Material	LGS	Low Gravity Solids
MAASP	Maximum Allowable Annular Test Surface Pressure	MBT	Methylene Blue
MDT	Modular Dynamic Tool	min	Minute
MMS	Magnetic Multi Shot	MSS	Magnetic Single Shot
MT	Metric Tonnes	MSDS	Materials Safety Data Sheet
MWD	Measurement While Drilling	MW	Mud Weight
N/A	Not Applicable	NBRR	Near Bit Roller Reamer
NDT	Non Destructive Testing	NMDC	Non Magnetic Drill Collar
		NRV	Non Return Valve System
OD	Outside Diameter	OE	Operations Engineer
OGL	Operations Geologist	OH	Open Hole System
P & A	Plug and Abandon	PE	Petroleum Engineer
Pfc	Final Circulating Pressure	Pic	Initial Circulating Pressure
ppg	Pounds per Gallon	POOH	Pull out of Hole
psi	Pounds per square inch	ppm	Parts per Million
PVT	Pressure Volume Temperature.	PV	Plastic Viscosity
QA/QC	Quality Assurance/ Quality Control		
RFT	Repeat Formation Tester	RIH	Run in Hole
ROP	Rate of Penetration	rpm	Revolutions per Minute
RT	Rotary Table		
SCR	Slow Circulating Rate	sec/ qt	Seconds per quart
SEO	Statement of Environmental Objectives	SF	Safety Factor
SICP	Shut-in Casing Pressure	SIDPP	Shut-in Drill Pipe Pressure
SITHP	Shut-in Tubing Head Pressure	spm	Strokes per Minute
sx	Sacks		
TOC	Top of Cement	TP	Tool Pusher
TVD	True Vertical Depth	TD	Total Depth
UHF	Ultra High Frequency	TLC	Tough Logging Conditions
USIT	Ultra sonic imaging tool)		
VDL	Variable Density Log		
WGL	Wellsite Geologist	WOB	Weight on Bit
WOC	Waiting on Cement		
wt	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
Preparing Site and Rig -Up		
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.		
Pre-spud Checks		
On first well of the program ensure 3 rd 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		
Constructing Cellar		
Ensure the cellar has been dug and the cellar ring installed prior to rig move.		
Setting Conductor (This may be predrilled before rig arrives)		
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 ₂ as accelerator	8	
Drilling Surface Hole (This may be predrilled before rig arrives)		
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.		
Running Surface Casing		
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
Cementing Surface Casing		
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	
Installing Bradenhead.		
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.		
Drilling Intermediate/ Main Hole		
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	
Logging Open Hole		
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	
Open Hole DST		
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.	

Running Intermediate and Production Casing	
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 shootrack 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
Cementing Casing	
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.	8
Bleed-off pressure and measure backflow. Pressure test casing.	
Installing Casing Slips and Tubing/ Casing Spool	
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
Plugging and Abandonment	
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
Cleaning-up Lease	
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)
- H₂S 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.

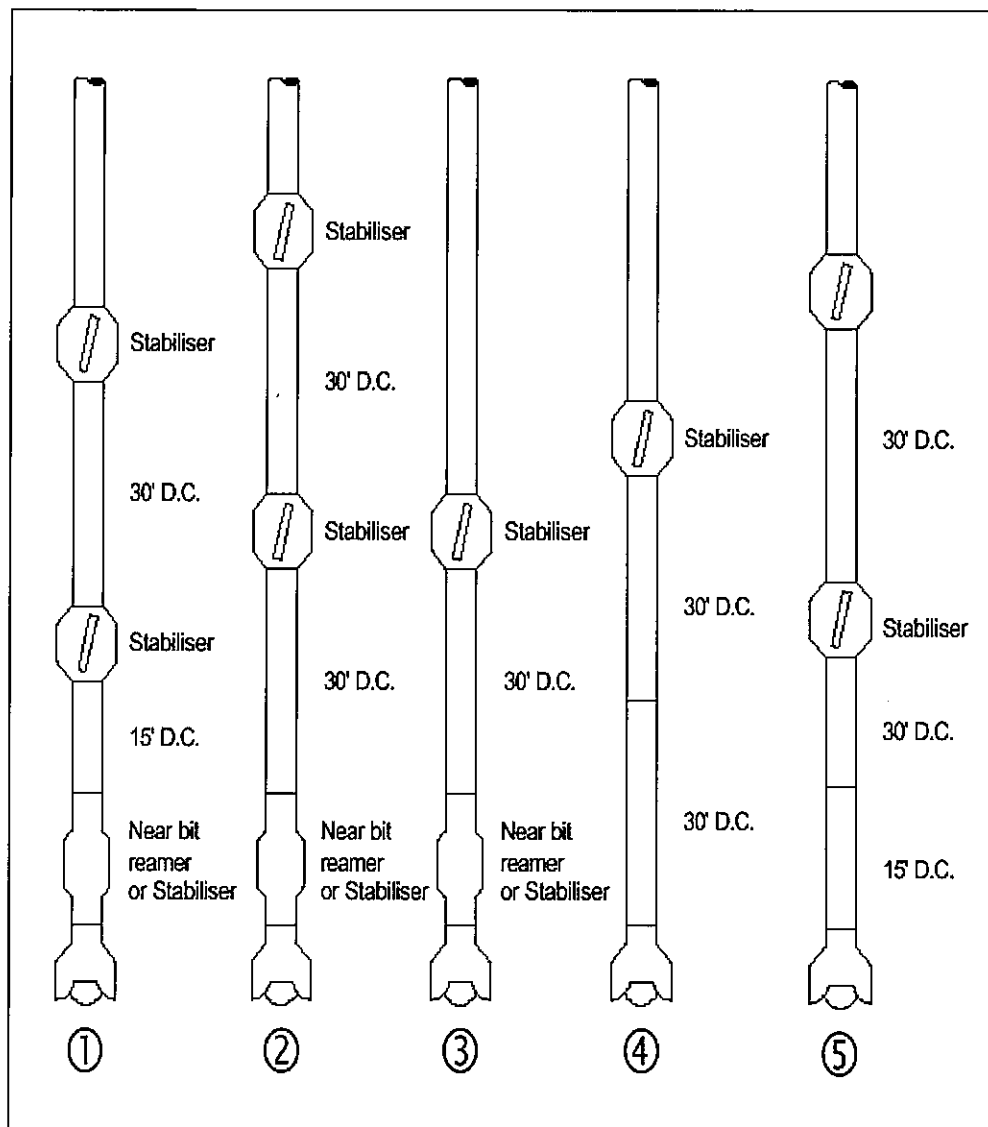


Figure 1. Vertical Well Generalised BHA Configurations

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 "locked", "stiff" or "packed" 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 reduced stiffness 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 "pendulum", 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 modified "pendulum" 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.

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

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 does 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"> • Drill with slick BHA • Work pipe frequently • Good hole cleaning • Drill bits (eg impreg on motor) • Air drill • Hammer drill • Low mud weights. • LCM
Low pressure and permeable water-bearing sands at shallow depths	Hole instability	<ul style="list-style-type: none"> • Low mud weights and effective hole cleaning are essential to minimise losses and washouts
Poor wall filtercake	Tight hole	<ul style="list-style-type: none"> • Low mud weight combined with optimal rheology, fluid loss and hole cleaning should minimise the problem
Sloughing at deeper depths	Hole instability	<ul style="list-style-type: none"> • 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.
Fragile coal seams	Packing-off hole	<ul style="list-style-type: none"> • Avoid packing off hole when pulling the BHA and swabbing the hole by pulling slowly through known coal seams. • Cuttings returned to surface should be closely monitored and compared to the ROP. Inconsistencies may indicate a sloughing coal seam higher in the hole • 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. • 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.

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

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

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

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"> Ensure that the drilling fluid formulation is designed to cope with gumbos and swelling shales where they are indicated.
Wellsite	<ul style="list-style-type: none"> Trip cautiously through swelling formations. 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. After pulling into a tight spot, run back into gauge hole and circulate before back reaming out. Sections of the hole found to be tight on the way out of the hole shall always be reamed on the trip back in. 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. No unnecessary time shall be spent in open hole.

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"> Offset well data shall be reviewed for incidents of key seating and any occurrences shall be noted in the Drilling Program. 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.
Wellsite	<ul style="list-style-type: none"> Ream any severe doglegs to prevent key seats developing. 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.

Table 11. Prevention of Key Seating.

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">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.
Wellsite	<ul style="list-style-type: none">Bits and stabilisers shall always be gauged after each trip.If the bit is pulled undergauge the whole of the section drilled by the previous bit may require reaming.Do not trip a BHA of increased stiffness into the hole rapidly. Expect to have to ream.If the hole is suspected to be undergauge, extreme caution must be applied when tripping into the hole.

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 HSWWE 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_{max} = Height of tool joint shoulder above slips - ft

Y_m = 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 length³

(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)
2 3/8	4.85	0.66
	6.65	0.87
2 7/8	6.85	1.12
	10.40	1.60
3 1/2	9.50	1.96
	13.30	2.57
	15.50	2.92
4	11.85	2.70
	14.00	3.22
	15.70	3.58
4 1/2	13.75	3.59
	16.60	4.27
	20.00	5.17
	22.82	5.68
5	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 1/4" 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
Drillpipe	Magnetic Particle/Calliper	6 months	Inspection Company	DSV
HWDP	Magnetic Particle/Calliper	3 months	Inspection Company	DSV
Drillcollars	Magnetic Particle/Calliper	3 months	Inspection Company	DSV
Crossovers	Magnetic Particle/Calliper	3 months	Inspection Company	DSV
Saver subs	Magnetic Particle/Calliper	6 months	Inspection Company	DSV
Jars	Magnetic Particle/Calliper	6 months	Jar supplier	DSV
Stabilizers	Magnetic Particle/Calliper	6 months	Inspection Company	DSV
Roller reamers	Magnetic Particle/Calliper	6 months	Inspection Company	DSV
Pony DC.	Magnetic Particle/Calliper	6 months	Inspection Company	DSV
NMDC	Magnetic Particle/Calliper	6 months	Inspection Company	DSV
Fishing tools.	Magnetic Particle/Calliper	After use	Inspection Company	DSV
MWD tools	Magnetic Particle/Calliper	After use	Tool supplier	DSV
Motors	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 suctions, 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
Alkalinity Control	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 / CO ₂ 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
Biocide	Alkyl Dithiocarbamates		
	Glutaraldehyde	Glutaraldehyde	Prevent bacterial decay of polymers
Corrosion Control	Filming Amine	Proprietary blend	Minimise corrosion of tubulars from oxygen, CO ₂ and/or H ₂ S
	Multi- component	Proprietary blend	Minimise corrosion of tubulars from oxygen, CO ₂ and/or H ₂ S
	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
Defoamer	Defoam	Proprietary	Defoam aerated muds, surfactant
	Stearate	Aluminium stearate	Defoam aerated muds
Detergent	Mud detergent, DD, etc.	Metallic salty of fatty acid (soap)	Minimise bit balling, emulsifier, rig wash
Dispersant	CF Ligno	Chrome free Lignosulphate	Thinner; reduces fluid loss, emulsifier, shale inhibitor
Fluid Loss Control	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, Cypan, etc	Sodium Polyacrylate	Reduces high temperature fluid loss; thinner
	Modified polymers	Proprietary Organic polymers	Reduces high temperature fluid loss; thinner
Shale Inhibitor	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
Viscosifiers	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)
Weighting Agents	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)
Miscellaneous	Calcium Chloride	Calcium Chloride	Brine additive (max. 11.7 ppg); cement accelerator
Lost Circulation Material	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
Pipe Free Agent		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"> • Must be operated as efficiently as possible, at all times, in order to maximise the amount of solids removed after exiting the wellbore. • Must be switched on immediately before running in the hole to clean the mud displaced by the drill string and BHA. • Flow shall be distributed evenly over all available shakers. • 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. • Cuttings should not be allowed to dry hard upon the screens. • Shakers shall not be by-passed, unless absolutely necessary and as authorised by the DSV • Shakers should not be run dry as this leads to increased wear and premature screen failure
Shaker Screens	<ul style="list-style-type: none"> • 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. • Screens shall be inspected regularly and changed out or patched immediately when defects are identified. • Operations should not be allowed to continue with a torn or ineffective screen. • Screens shall be washed down regularly e.g. on connections, prior to tripping out of the hole and before shakers are switched off. • Adequate stocks of screens, in an appropriate range of sizes, shall be maintained on location at all times. • The mud engineer should record the number of screens used on the daily mud report. • Ensure shaker screens are installed and tensioned as per the manufactures procedures

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.

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

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

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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
Surface hole	MSS/Totco	Every 150 m	3 degrees	1.5 degrees/30 m
Intermediate hole	MSS/Totco	Every 150 m	5 degrees	1.5 degrees/30 m
Production hole	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 stationery 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
Planning	<ul style="list-style-type: none"> • Survey type shall be based on the anti-collision requirements (if applicable), survey tool accuracy, target size and depth. • Survey accuracy objectives shall be specified for each well.
Calculations	<ul style="list-style-type: none"> • The preferred method of survey calculation is the Minimum Curvature method. Other calculation methods may be used to verify survey results. • 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.
Reporting	<ul style="list-style-type: none"> • All survey data reported to on the Daily Drilling report shall be UNCORRECTED (e.g. referenced to magnetic north). • The Azimuth shall be reported in degrees and not quadrants (i.e. will be reported as 190° not S10°W). • 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. • Survey results shall be referenced to the local grid for reporting purposes.
Verification	<ul style="list-style-type: none"> • The quality of all multi-shot surveys taken shall be checked by the Surveying

	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.

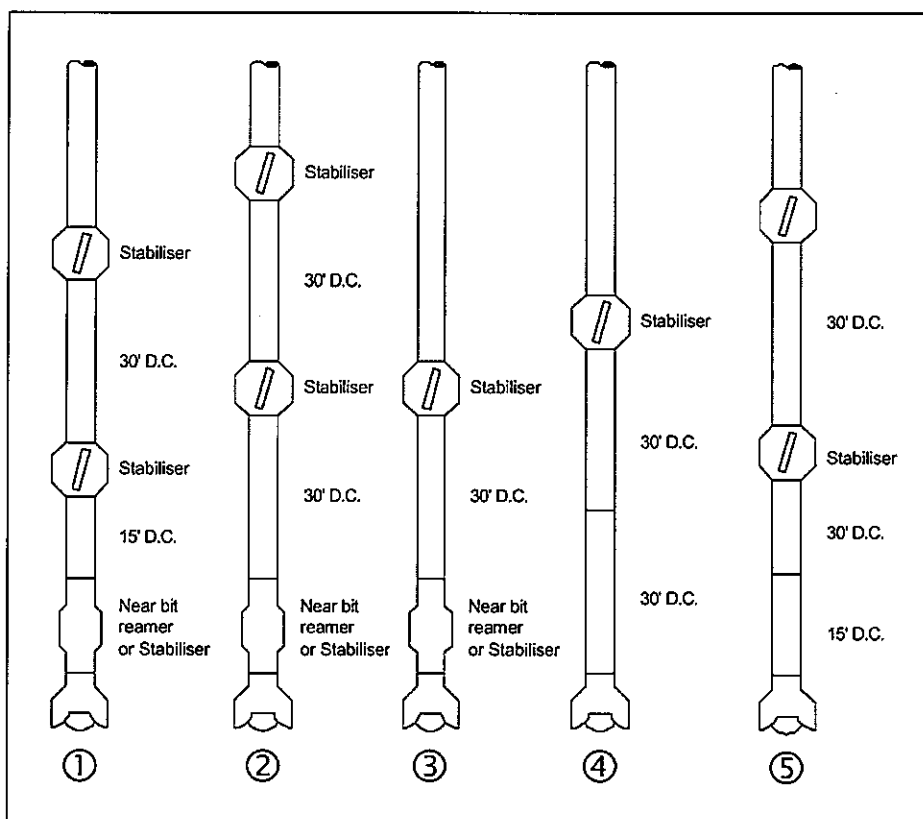


Table 30. Standard BHA Configurations in Nominally Vertical Wells


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

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 || 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.

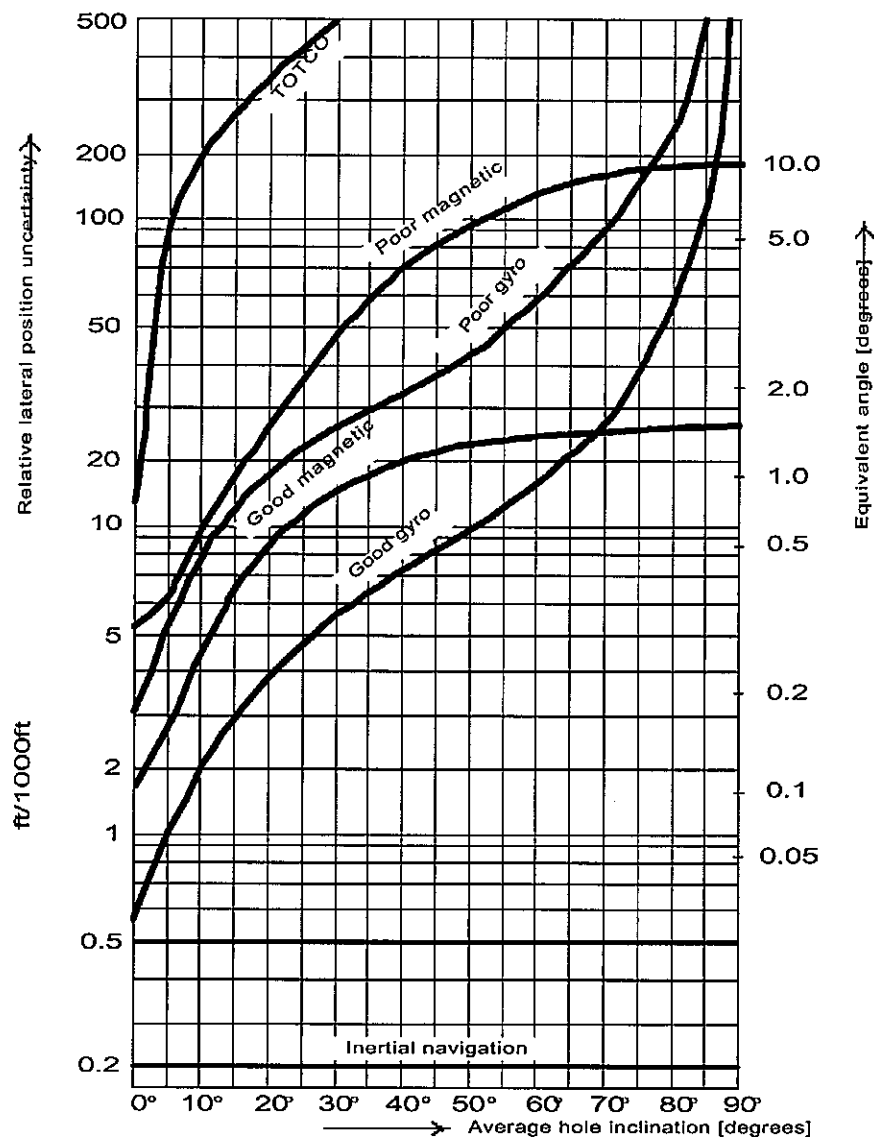


Figure 5. Lateral position Uncertainty – Tool Comparison

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 $975-550\text{m} = 425\text{m}$ { $3200-1800' = 1400'$ }
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 $1143-975\text{m} = 168\text{m}$ { $3750-3200' = 550'$ }
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.

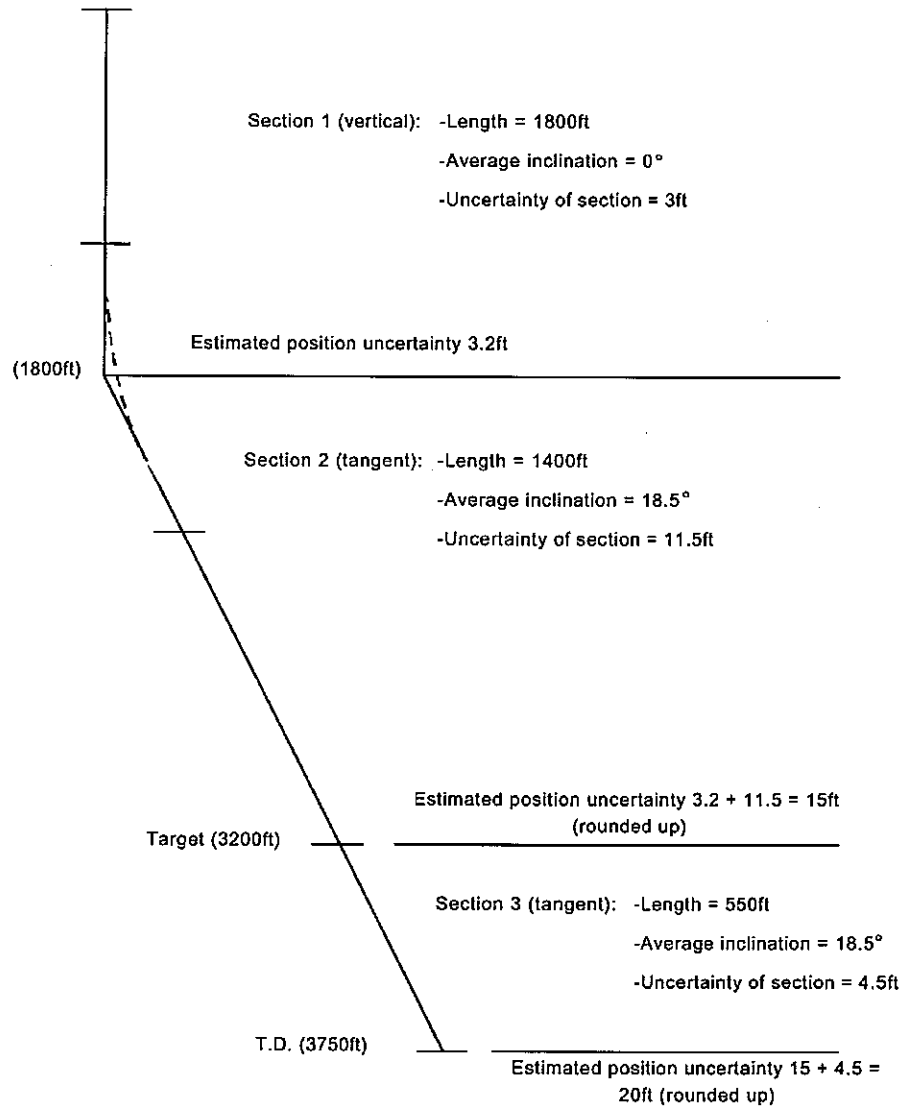


Figure 6. Simplified Sections of Example Well

Appendix III: Ellipse of Uncertainty

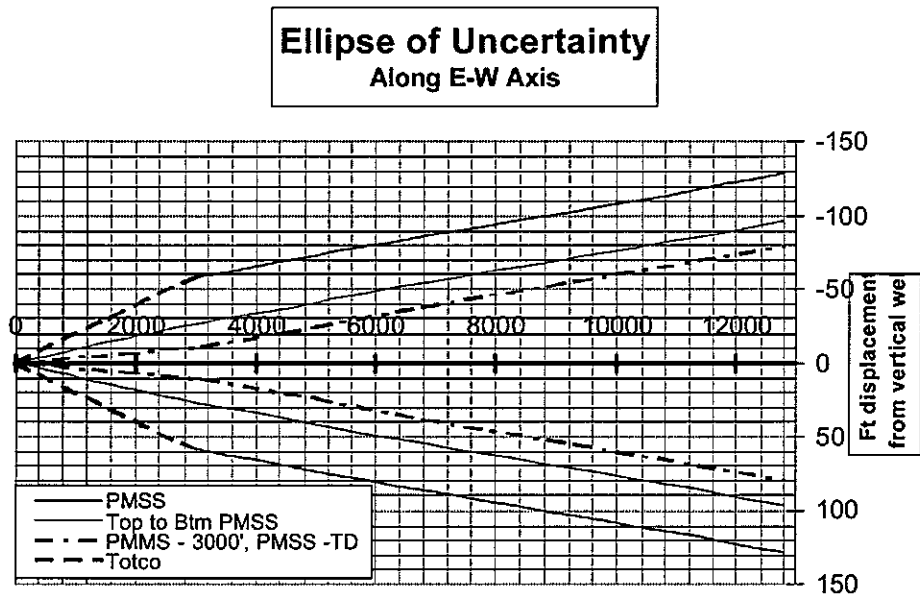


Figure 7. Ellipse of Uncertainty – Along E-W Axis

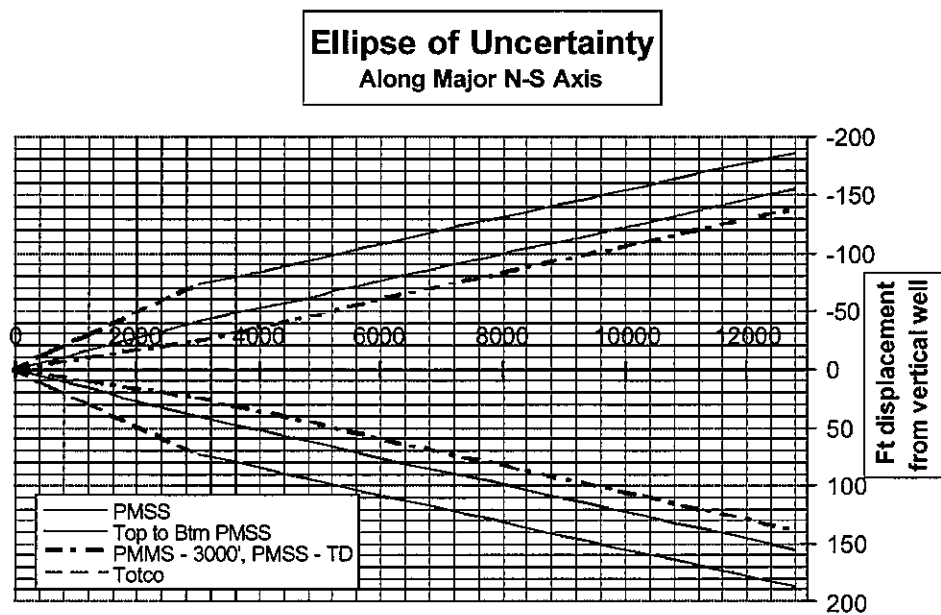


Figure 8. Ellipse of Uncertainty – Along Major N-S Axis

**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.

Task	Performed by	Verified by
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.

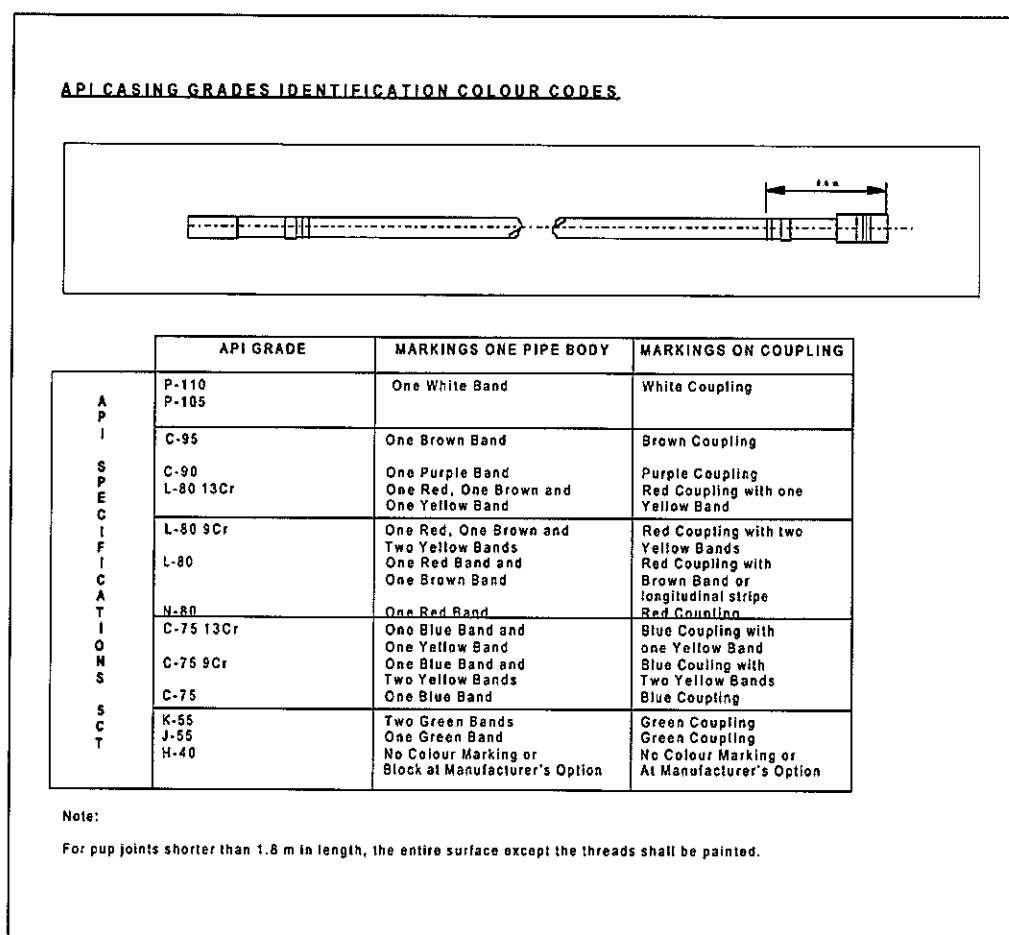
Casing Type	Function
Conductor Pipe	<ul style="list-style-type: none"> Provides structural strength to cover unconsolidated surface formations Serves as a circulating system for the drilling fluid Guides the drilling and subsequent casing strings into the hole
Surface Casing	<ul style="list-style-type: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

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

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
Bradenhead	
<ul style="list-style-type: none"> • Check wellhead threads are compatible with the casing being run. • Check condition of wellhead threads regardless of new or reconditioned wellhead 	
Casing and cement calculations completed and checked	
<ul style="list-style-type: none"> • Correct number of joints of the correct weight and grade included • Shoe track and rat hole as per program • Casing tally and running list prepared. Running list faxed to DM. 	
Landing string drifted and checked	
Cement equipment as follows checked by Cementing Contractor	
<ul style="list-style-type: none"> • Cement head casing connection • Top and bottom plugs installed as appropriate,. Note a ball may be used below the top plug in 3 1/2" tubing • Installation witnessed and checked by DSV • Float shoe and float collar installed and checked 	
Centralisers, cement basket, stop collars and pins on rig floor	
Casing running equipment rigged up / on rig floor	
<ul style="list-style-type: none"> • Power tongs • Pick up elevators • Casing elevators • Hand slips • Klampons • Circulating head for all types of casing being run. Check threads compatible with casing • Spider slips (if required) • Spider elevators (if required) • Torque turn equipment (if required) 	
Thread lock and casing compound on rig floor	
Snub and back up lines correctly installed and checked	
Stabbing board checked by stabber	
Drill floor cleared of unnecessary equipment	
Crew safety toolbox meeting conducted	
Surge / swab calculations completed as required	

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 Drilling Program .	
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. The lesser of pipe body yield strength or thread yield strength (of top pipe)
1.6
- or:
- b. The lesser of the weakest pipe or thread + 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 ³ /sk	Mix Water gal/sx	Unconfined Compress. Strength	Coverage	Excess	Preflush / Spacers	Displacement Fluid
Conductor (All wells)	Class A with 1-2%CaCl ₂	70	15.8	1.18	5.2		To cellar floor	N/A	N/A	N/A
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
Intermediate & Production Csg										
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	Interm'd: Mud Prod'n: Brine
Tail	Class G	<230 °F	15.8	1.16	5.01	4,000 psi	Min 60m above Hydrocarbons			
Intermediate and Production Casing										
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	Interm'd: Mud Prod'n: Brine
Tail	Class G plus silica flour	>230 °F	15.6	1.56	6.66	4500 psi	Min 60m above Hydrocarbons			

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

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 Caliper log +10% excess
Liner	Top of liner lap	Minimum 120m of tail or to min 60m above top of hydrocarbon-bearing reservoirs.	Gauge hole + 20% excess or Caliper log +10% excess (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% CaCl₂.

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

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"> • <i>Total Volume (bbls)</i> = <i>Shoetrack vol</i> + <i>(rathole + excess)</i> + <i>(annulus to top of tail + excess)</i> • <i>Total Volume (cu. ft.)</i> = <i>bbls</i> × 5.615 <p>1.2 Calculate Cement Requirements</p> <ul style="list-style-type: none"> • <i>Sacks of Cement</i> = <i>slurry cu. ft.</i> + <i>slurry yield (cu. ft./sx)</i> • <i>Tonnes of Cement (MT)</i> = $\left(\frac{\text{sacks of cement} \times 94}{2200} \right)$ <p>1.3 Calculate Mixwater Requirements</p> <ul style="list-style-type: none"> • <i>Total Mixwater (bbls)</i> = $\left(\frac{\text{sacks of cement} \times \text{mixwater (gal/sx)}}{42} \right)$ + <i>excess(dependent on job)</i> <p>1.4 Calculate Additive Requirements (for each additive)</p> <ul style="list-style-type: none"> • <i>Total Volume</i> = <i>Concentration (gal / sk)</i> × <i>sacks of cement (BWOC)</i> • <i>Total Volume</i> = <i>Concentration (% BWOC)</i> × <i>total mix water (BWOC)</i> <p>Note: • 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"> • <i>Total Volume (bbls)</i> = $\frac{(\text{hole / csg annulus to TOC or shoe}) + (\text{csg / csg annulus vol to TOC (if require overlap)})}{5.615}$ • <i>Total Volume (cu. ft.)</i> = <i>bbls</i> × 5.615 <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"> • <i>Total Volume to Float Collar (bbls)</i> • <i>Mud Displacement Volume (bbls)</i> • <i>Pump Strokes to Bump Plug</i>
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"> • <i>lit of Spacer / preflush</i> = $\frac{\text{volume (bbls)}}{\left(\frac{\text{hole ID}^2 - \text{csg ID}^2}{1029.4} \right)}$ • <i>Loss in psi hydrostatic</i> = <i>(mud wt - spacer wt) × 0.0519 × spacer ht</i> • <i>Hydrostatic Gradient</i> = $\text{MW (ppg)} - \left(\frac{\text{hyd loss (psi)}}{0.052 \times \text{Depth of Interest (DOI) (ft.)}} \right)$

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) $= wt\ cmt\ (ppg) \times tail\ ht \times 0.052$</p>
	<p>5.2 Calculate Cement Hydrostatic (Lead) $= wt\ cmt\ (ppg) \times lead\ ht \times 0.052$</p>
	<p>5.3 Calculate Spacer Hydrostatic <ul style="list-style-type: none"> • Calculate spacer ht = $\left(\frac{spacer\ vol}{annulus\ volume\ (bbl / ft)} \right)$ • Calculate spacer Hydrostatic = $spacer\ wt\ (ppg) \times ht\ (ft) \times 0.052$ </p>
	<p>5.4 Calculate Preflush Hydrostatic (as applicable) <ul style="list-style-type: none"> • Calculate preflush ht = $\left(\frac{preflush\ vol}{annulus\ volume\ (bbl / ft)} \right)$ • Calculate Preflush Hydrostatic = $preflush\ wt \times ht \times 0.052$ </p>
	<p>5.5 Calculate Mud Hydrostatic (as applicable) <ul style="list-style-type: none"> • Calculate Mud ht = top of preflush to surface (ft) • Calculate Mud Hydrostatic = $MW \times ht \times 0.052$ </p>
	<p>5.6 Calculate Total EMW = $Total\ of\ (5.1 - 5.5) + 0.052 \times Depth\ (ft)$</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"> • Total Time = $(slurry\ bbls + pumping\ rate) + 10\ minute\ pre\ mix\ time\ (or\ as\ advise)$ </p>
	<p>6.2 Calculate Post Cement Spacer/Post Flush Time <ul style="list-style-type: none"> • Total Time = $bbls + pumping\ rate\ (bpm)$ </p>
	<p>6.3 Calculate Displacement Time <ul style="list-style-type: none"> • Total Time = $displacement\ volume\ (bbls) + displacement\ rate\ (bpm)$ </p>
	<p>6.4 Calculate Total Job Time $Total\ of\ (6.1 - 6.4) \times 2\ (100\% SF)$</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 $ht (ft) = \frac{vol\ preflush\ (bbls)}{\left(\frac{ID^2 - ID^2_{inner}}{1029.4}\right)}$</p> <p>1.2 Calculate Hydrostatic loss/gain $loss/gain\ (psi) = (MV - PF\ wt) \times 0.052 \times ht\ preflush$ + check against pore pressure for safety margin.</p>
2. Calculate Slurry Volume For Job	<p>2.1 Calculate shoetrack volume $= shoetrack\ length \times \left(\frac{ID_{liner}^2}{1029.4}\right)$</p> <p>2.2 Calculate rathole Volume $= rathole\ length \times \left(\frac{OIL^2}{1029.4}\right)$</p> <p>2.3 Calculate O.H./Liner Annulus $= (Liner\ Shoe\ Depth - Casing\ Shoe\ Depth) \times \left(\frac{OIL^2 - inner\ OIL^2}{1029.4}\right)$</p> <p>2.4 Calculate Liner/Casing Annulus $= (Casing\ Shoe - Line\ Hanger\ Depth) \times \left(\frac{ID_{casing}^2 - inner\ OIL^2}{1029.4}\right)$</p> <p>2.5 Calculate Casing Vol to planned TOC $= (Hanger\ Depth - TOC) \times \left(\frac{ID_{casing}^2 - inner\ OIL^2}{1029.4}\right)$</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.) $= Total\ Vol\ (bbls) \times 5.615$</p>
3. Calculate Cement Mixwater and Additive Volumes	<p>3.1 Calculate cement volume required $= \frac{Slurry\ Vol\ (cu.\ ft.)}{yield\ (cu.\ ft./sk)}$</p> <p>3.2 Calculate cement requirement (MT) $= \frac{No.\ sacks \times 94}{2200}$</p> <p>3.3 Calculate Mixwater Volume (bbls) $= \frac{Mixwater\ gal / sk \times No.\ sacks}{42} + excess$</p> <p>3.4 Calculate Additive Requirements (for each) $= additive\ concentration\ (gal / sk) \times No.\ sacks\ cement$</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 $= length\ (ft) \times \left(\frac{ID_{liner}^2}{1029.4}\right)$</p>
5. Calculate Displacement Volume to Land Dart in Wiper Plug	<p>5.1 Calculate Volume to Land Dart = Total Displacement Volume $= length\ to\ wiper\ plug\ seat \times \left(\frac{ID_{rammer\ string}^2}{1029.4}\right)$</p> <p>5.2 Calculate Mud Displacement Volume $= total\ disp\ vol - spacer\ behind\ volume$</p> <p>5.3 Calculate Strokes to Shear Wiper Plug $= \frac{Result\ of\ 5.2}{Pump\ output\ (bbl / sk)}$</p>

Table 53. Primary Cementing Calculations – Liner (i)

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

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) $= \text{required ht} \times \left(\frac{ID \text{ csg}^2 \text{ or } OH^2}{1029.4} \right)$</p> <p>1.1.1 If across shoe or stub, calculate</p> <ul style="list-style-type: none"> a) ht cmt in cased hole section b) volume cmt in in cased hole section c) ht cmt in open hole section d) volume cmt in open hole section e) total volume = sum 'b' + 'd' <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) $= \left(\frac{\text{slurry vol (cu. ft.)}}{\text{slurry yield (cu. ft./sk)}} \right)$</p> <p>2.2 Calculate cement required (MT) $= \left(\frac{\text{no. of sacks} \times 94}{2200} \right)$</p> <p>2.3 Calculate mixwater volume $\text{gals} = \text{no. of sacks cmt} \times \text{mixwater (gal / sk)} + \text{excess}$ $\text{bbls} = \left(\frac{\text{gals mixwater}}{42} \right)$</p> <p>2.4 Calculate additive requirements (for each) $= \text{no. of sacks cmt} \times \text{additive concentration (gal / sk)}$</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 plpo)</p> $ht = \frac{\text{vol spacer or preflush}}{\left(\frac{\text{hole ann vol}^2 - \text{spacer vol}^2}{1029.4} \right)}$ <p>3.2 Calculate hydrostatic loss/gain</p> $psi = (MW \text{ (ppg)} - \text{spacer / preflush} \times t \text{ (ppg)}) \times 0.052 \times \text{spacer ht preflush}$ <p><u>Note:</u> * Check resultant EMW against any exposed formation pore pressures at depth of interest.</p>

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

PRIMARY CEMENTATION CALCULATIONS - BALANCED PLUG	
PROCEDURAL STEP	SUB CALCULATIONS
4. Calculate Spacer Volume Behind Cement	4.1 Calculate volume behind (bbls) $= ht \text{ spacer or preflush} \times \left(\frac{pipe \text{ ID}^2}{1029.4} \right)$
5. Calculate Displacement Volume to Balance	<p>5.1 Calculate cmt ht prior to pull back $ht \text{ ft} = \left(\frac{slurry \text{ volume (bbls)}}{annulus \text{ vol (bbl / ft)} + DP \text{ string capacity (bbl / ft)}} \right)$</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 $ht \text{ spacer (ft)} = \left(\frac{spacer \text{ volume}}{annulus \text{ vol (bbl / ft)} + DP \text{ capacity (bbl / ft)}} \right)$</p> <p>5.3 calculate ht of mud to displace $= \text{cement string length} - \text{slurry ht (5.1)} - \text{spacer ht (5.2)}$</p> <p>5.4 Calculate displacement volume (bbls) $= \left(\frac{DP \text{ ID}^2}{1029.4} \right) \times ht \text{ of mud required (5.3)}$</p> <p>5.5 Calculate displacement volume (STKS) $= \frac{(\text{disp vol (bbls)} - 2 \text{ bbls under displacement})}{pump \text{ output (bbl / stk)}}$</p>

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