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Great South Land
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Great South Land Minerals

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Annual Report

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Drilling

-Bellevue

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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	• 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	• This string is normally cemented to surface • Provides blow-out protection • Seals off water aquifers • Prevents loss of circulation
Intermediate Casing	• 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	• 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	• Separates/ isolates productive zones from other reservoir and non reservoir zones • Tied back to previous casing string. • Normally cemented back to liner hanger.

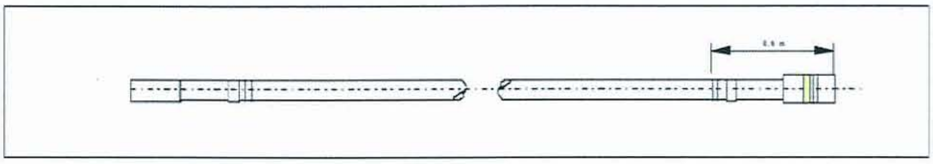
Table 35. Casing Types and Functions.

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 GRADES IDENTIFICATION COLOUR CODES



	API GRADE	MARKINGS ONE PIPE BODY	MARKINGS ON COUPLING
API SPECIFICATIONS 5CT	P-110 P-105	One White Band	White Coupling
	C-95	One Brown Band	Brown Coupling
	C-90	One Purple Band	Purple Coupling
	L-80 13Cr	One Red, One Brown and One Yellow Band	Red Coupling with one Yellow Band
	L-80 9Cr	One Red, One Brown and Two Yellow Bands	Red Coupling with two Yellow Bands
	L-80	One Red Band and One Brown Band	Red Coupling with Brown Band or longitudinal stripe
	N-80	One Red Band	Red Coupling
	C-75 13Cr	One Blue Band and One Yellow Band	Blue Coupling with one Yellow Band
	C-75 9Cr	One Blue Band and Two Yellow Bands	Blue Couling with Two Yellow Bands
	C-75	One Blue Band	Blue Coupling
	K-55	Two Green Bands	Green Coupling
	J-55	One Green Band	Green Coupling
	H-40	No Colour Marking or Block at Manufacturer's Option	No Colour Marking or At Manufacturer's Option

Note:

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

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

7.3.3 Casing Setting Depth

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

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

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

7.3.4 Casing Design Factors

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

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

Table 37. Casing Design Loading Criteria.

7.3.5 Conductor Pipe

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

7.3.6 Shoe Track Configuration

Shoe track requirements:

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

7.3.7 Centralisation

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

Casing String	Centralisation Programme
Surface Casing	• 3 m from shoe • Centrally on the second joint • Across the third coupling • First coupling below the conductor.
IntermediateCasing	• 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	• 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 • **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 • 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 • Cement head casing connection • Top and bottom plugs installed as appropriate,. Note a ball may be used below the top plug in 3 ½" 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 • 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. $$\frac{\text{The lesser of pipe body yield strength or thread yield strength (of top pipe)}}{1.6}$$

or:

b. $$\frac{\text{The lesser of the weakest pipe or thread + Weight in air of casing above it}}{1.6}.$$

7.5.5 Reporting

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 ft³/sk	Mix Water gal/sx	Unconfined Compress. Strength	Coverage	Excess	Preflush / Spacers	Displacement Fluid
Conductor (All wells)		Class A with **1-2%CaCl2**	70	15.8	1.18	5.2		To cellar floor	N/A	N/A	N/A
Surface Casing											
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											
Intermediate and Production Casing (BHT < 230°F	Lead	Class G plus bentonite		12.8	2.11	11.78		150 m into previous casing	Gauge + 20% or Caliper + 10%	10 Bbl Dual Spacer, 40 bbl SAPP, 10 Bbl Dual Spacer	
	Tail	Class G	<230 °F	15.8	1.16	5.01	4,000 psi	Min 60m above Hydrocarbons			Interm'd: Mud Prod'n: Brine
Intermediare and Production Casing (BHT > 230°F	Lead	Class G plus bentonite		12.8	2.11	11.78		150 m into previous casing	Gauge + 20% or Caliper + 10%	10 Bbl Dual Spacer 40 bbl SAPP, 10 Bbl Dual Spacer	
	Tail	Class G plus silica flour	>230 °F	15.6	1.56	6.66	4500 psi	Min 60m above Hydrocarbons			Interm'd: Mud Prod'n: Brine

Table 45. Guide to Standard Cement Slurries

8.5 SPACERS

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

Displacement	Formulation
High Annular Velocity Slurry Displacements	• 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	• 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	• 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	• 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.
* Well name and number.
* Date sample taken.
* Expected date of first cementation.
* 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).

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% $CaCl_2$.

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 ¼ to ½ 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 ¼ to ½ 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 untill 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	• Class of cement and amount used • Cost of cement
Additives	• Names of additives and amounts used • Cost
Spacer	• Composition • Cost
Cement Placement	• Estimated TOC
Volume Requirements	• Spacers • Slurries • Displacement water
Operations Information	• General (e.g. pipe reciprocation) • Cement wiper plugs • Displacement rate and pump efficiency • Plug bump volume, over-displacement
Pressure Chart	• Description of all operations marked on chart • Start and stop times • Pressure test of casing
Drilling Fluid Data	• Type • Weight • Rheology and gels
Centralisation	• Type, depths and spacing
Cementer's Comments	• 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	1.1 Calculate Volume • *Total Volume (bbls) = Shoetrack vol + (rathole + excess) + (annulus to top of tail + excess)* • *Total Volume (cu. ft.) = bbls × 5.615* 1.2 Calculate Cement Requirements • Sacks of Cement = slurry cu. ft. ÷ slurry yield (cu. ft./sx) • *Tonnes of Cement (MT)* $= \left(\dfrac{\text{sacks of cement} \times 94}{2200}\right)$ 1.3 Calculate Mixwater Requirements • Total Mixwater (bbls) $= \left(\dfrac{\text{sacks of cement} \times \text{mixwater (gal/sx)}}{42}\right)$ *+ excess (dependent on job)* 1.4 Calculate Additive Requirements (for each additive) • Total Volume = Concentration (gal / sk) × sacks of cement (BWOC) • Total Volume = Concentration (% BWOC) × total mix water (BWOC) <u>Note</u>: • Water excess to be considered if additives are mixed with water.
2. Calculate Lead Slurry Data	2.1 Calculate Slurry Volume • *Total Volume (bbls) = (hole / csg annulus to TOC or shoe) + (csg / csg annulus vol to TOC (if require overlap))* • Total Volume (cu. ft.) = bbls × 5.615 2.2 Calculate Cement Requirements *(As per 1.2)* 2.3 Calculate Mixwater Requirements *(As per 1.3)* 2.4 Calculate Additive Requirements *(As per 1.4)*
3. Calculate Displacement Data	3.1 Calculate Displacement Volume • *Total Volume to Float Collar (bbls)* • *Mud Displacement Volume (bbls)* • *Pump Strokes to Bump Plug*
4. Calculate Minimum Hydrostatic During Job	4.1 Assume minimum hydrostatic when (low weight) spacer pre flush in annulus • Ht of Spacer / preflush $= \dfrac{\text{volume (bbls)}}{\left(\frac{\text{hole ID}^2 - \text{csg OD}^2}{1029.4}\right)}$ • *Loss in psi hydrostatic = (mud wt - spacer wt) × 0.0519 × spacer ht* • *Hydrostatic Gradient = MW (ppg) -* $\left(\dfrac{\text{hyd loss (psi)}}{0.052 \times \text{Depth of Interest (DOI) (ft)}}\right)$

Table 52. Primary Cementing Calculations – Casing (i)

PRIMARY CEMENTATION CALCULATIONS - CASING	
PROCEDURAL STEP	**SUB CALCULATIONS**
5. Calculate Maximum Hydrostatic	5.1 Calculate Cement Hydrostatic (Tail) $= wt\ cmt\ (ppg) \times tail\ ht \times 0.052$ 5.2 Calculate Cement Hydrostatic (Lead) $= wt\ cmt\ (ppg) \times lead\ ht \times 0.052$ 5.3 Calculate Spacer Hydrostatic • $Calculate\ spacer\ ht = \left(\frac{spacer\ vol}{annulus\ volume\ (bbl/ft)}\right)$ • $Calculate\ spacer\ Hydrostatic = spacer\ wt\ (ppg) \times ht\ (ft) \times 0.052$ 5.4 Calculate Preflush Hydrostatic (as applicable) • $Calculate\ preflush\ ht = \left(\frac{preflush\ vol}{annulus\ volume\ (bbl/ft)}\right)$ • Calculate Preflush Hydrostatic = preflush wt × ht × 0.052 5.5 Calculate Mud Hydrostatic (as applicable) • $Calculate\ Mud\ ht = top\ of\ preflush\ to\ surface\ (ft)$ • $Calculate\ Mud\ Hydrostatic = MW \times ht \times 0.052$ 5.6 Calculate Total EMW = $Total\ of\ (5.1 - 5.5) \div 0.052 \div Depth\ (ft)$ Note: * Calculate hydrostatic at known weak points in the wellbore and advise DTL if fracture gradient will be exceeded.
6. Calculate Job Time	6.1 Calculate Mixing/Pumping Time • $Total\ Time = (slurry\ bbls \div pumping\ rate) + 10\ minute\ pre\ mix\ time\ (or\ as\ advise)$ 6.2 Calculate Post Cement Spacer/Post Flush Time • Total Time = bbls ÷ pumping rate (bpm) 6.3 Calculate Displacement Time • $Total\ Time = displacement\ volume\ (bbls) \div displacement\ rate\ (bpm)$ 6.4 Calculate Total Job Time Total of (6.1 - 6.4) × 2 (100% SF) * Compare to thickening time and advise DTL if thickening time is insufficient.

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

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 $= \{\text{wiper plug seat - landing collar}\} \times \left(\frac{ID\ liner^2}{1029.4}\right)$ 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) $= cmt\ wt \times 0.052 \times cmt\ ht$ 7.1.2 Calculate spacer hyd (psi) $= spacer\ wt \times 0.052 \times spacer\ ht$ 7.1.3 Calculate mud hyd (psi) $= MW \times 0.052 \times (depth\ liner - cmt\ ht - spacer\ ht)$ 7.1.4 Calculate cmt hyd in liner $= shoetrack\ length \times 0.052 \times cmt\ wt$ 7.1.5 Calculate spacer behind in liner $= spacer\ ht \times 0.052 \times spacer\ wt$ 7.1.6 Calculate mud hyd in string $= MW \times 0.052 \times (shoe\ depth - cmt\ ht - spacer\ ht)$ 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 $ppg = \left(\frac{\sum(7.1.1 + 7.1.2 + 7.1.3)}{0.052 \times shoe\ depth}\right)$ <u>Note</u> * 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 $= string\ ppf \times length \times bouyancy\ factor\ of\ mud$ 8.2 Running wt in cement $= string\ ppf \times length\ in\ cmt \times bouyancy\ factor\ of\ cement$ <u>Note</u> * 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	1.1 Calculate Slurry Volume (bbls) $= required\ ht \times \left(\frac{ID\ csg^2\ or\ OH^2}{1029.4}\right)$ 1.1.1 If across shoe or stub, calculate 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' 1.2 Calculate Slurry Volume (cu. ft.) = Total vol (bbls) x 5.615
2. Calculate Cement and Additive Requirements	2.1 Calculate sacks cement required (no. of sacks) $= \left(\frac{slurry\ vol\ (cu.ft.)}{slurry\ yield\ (cu.\ ft./sk)}\right)$ 2.2 Calculate cement required (MT) $= \left(\frac{no.\ of\ sacks\ \times\ 94}{2200}\right)$ 2.3 Calculate mixwater volume $gals = no.\ of\ sacks\ cmt \times mixwater\ (gal/sk) + excess$ $bbls = \left(\frac{gals\ mixwater}{42}\right)$ 2.4 Calculate additive requirements (for each) $= no.\ of\ sacks\ cmt \times\ additive\ concentration\ (gal/sk)$ Note: * Excess water to be considered in additive requirement.
3. Calculate Minimum Hydrostatic	3.1 Calculate ht of spacer or preflush (worst case w/ preflush spacer out of pipe) $ht = \frac{vol\ spacer\ or\ preflush}{\left([illegible]\right)}$ 3.2 Calculate hydrostatic loss/gain $psi = (MW\ (ppg) - spacer/preflush\ wt\ (ppg)) \times 0.052 \times spacer\ ht\ preflush$ Note: * Check resultant EMW against any exposed formation pore pressures at depth of interest.

Table 54. Primary Cemnting 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)	$= \text{ht spacer or preflush} \times \left(\frac{\text{pipe } ID^2}{1029.4}\right)$
5. Calculate Displacement Volume to Balance	5.1	Calculate cmt ht prior to pull back	$\text{ht ft} = \left(\frac{\text{slurry volume (bbls)}}{\text{annulus vol (bbl/ft)} + \text{DP string capacity (bbl/ft)}}\right)$
		Note: 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.	
	5.2	Calculate ht spacer prior to pullback	$\text{ht spacer (ft)} = \left(\frac{\text{spacer volume}}{\text{annulus vol (bbl/ft)} + \text{DP capacity (bbl/ft)}}\right)$
	5.3	calculate ht of mud to displace	$= \text{cement string length} - \text{slurry ht (5.1)} - \text{spacer ht (5.2)}$
	5.4	Calculate displacement volume (bbls)	$= \left(\frac{DP\ ID^2}{1029.4}\right) \times \text{ht of mud required (5.3)}$
	5.5	Calculate displacement volume (STKS)	$= \frac{\text{(disp vol (bbls)} - \text{2 bbls under displacement)}}{\text{pump output (bbl/stk)}}$

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

CHAPTER 9
EVALUATION

TABLE OF CONTENTS

9.1 OBJECTIVES

The primary objectives of evaluation are:

- To obtain the maximum amount of subsurface information as detailed in the Drilling Program, in a safe and cost-efficient manner.

- To ensure that data acquisition is not impaired or damaged by drilling fluids or drilling practices during the drilling of the wellbore.

- To ensure that the DSV retains overall control and responsibility for the safe and efficient execution of all evaluation activities performed at the wellsite.

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

9.2 RESPONSIBILITIES

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

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

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

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

9.2.1 Generic Responsibilities for all Evaluation Activities

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

Table 55. Responsibilities for Evaluation Activities - Generic

9.2.2 Specific Evaluation Responsibilities

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

Table 56. Responsibilities for Evaluation Activities - Specific

9.3.0 ELECTRIC LOGGING

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

9.3.1 Responsibilities

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

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

9.3.2 Wireline Logging Safety

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

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

9.3.3 Wireline Logging Preparation

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

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

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

9.3.4 General Logging Operations

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

Operation	Guideline
Trip Tank	• The hole shall be circulated using the trip tank during logging operations. • The hole must be kept full throughout, and the trip tank volume recorded every 15 minutes. • The trend must be monitored whilst running in and pulling out.
Calibration	• The wireline logging depths must be set to zero at surface and checked when pulling out to surface. • Additional checks must be made at casing depths and at TD.
Tool Failure	• If a tool hangs up while running in, and the section has not been logged before, log whilst POOH. • If one of the detectors on a combination tool does not function properly, log with the remaining detectors which have not been recorded before. • Inform the DM of any tool failure. • If poor hole conditions are anticipated, always log in, as well as out of the hole to secure data.
Repeat Sections	• A 60 m repeat section must be made on each logging run, and a 30 m overlap with previous logging runs must be made. • When running a caliper tool in a section where the top of the logged interval is below the casing shoe a 30 m section over the shoe must be run to check shoe depth and caliper gauge.
Mud Sampling	• Mud shall be sampled from both the pits and flowline just before the end of circulation before a logging job for analysis and resistivity measurement. This must be repeated after check trips if resistivity tools are to be run.
Wiper Trips	• May be required to ensure that the hole and mud conditions remain stable.
Tension Limits	• The weak-point tension limit and cable tension limit must be checked and tool weight in mud calculated before entering open hole. • Normal logging tension should be checked every 300 m in open hole. This is especially important in deviated holes where significant drag can occur.

Table 57. Guidelines to General Logging Operations

9.3.4.1 Log Quality Control

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

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

acceptable range is ±10%.

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

9.3.5 Tough Logging Conditions

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

Planning and preparation

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

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

Running in Hole

The following considerations shall be adhered to:

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

9.3.6 Attempts to Free Stuck Logging Tools

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

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

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

<table>
<tr><th>Stuck Position</th><th colspan="2">Guideline</th></tr>
<tr><td>Stuck on Bottom</td><td colspan="2">If the tool is stuck on bottom, close the tool and pull to maximum safe tension to keep the weak-point intact.</td></tr>
<tr><td rowspan="3">Stuck during Logging Upward</td><td colspan="2">If the tool is stuck during logging upward, close the tool and try to go down.</td></tr>
<tr><td>Free to Descend:</td><td>• Make several attempts to pass the bridge</td></tr>
<tr><td>Not Free to Descend:</td><td>• Pull to maximum safe tension to keep weak-point intact</td></tr>
</table>

Table 58. Guidelines whilst Attempting to Free Stuck Logging Tools

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

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

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

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

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

9.3.7 Stripping Over

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

The following procedure shall be used:

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

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

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

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

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

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

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

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

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

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

9.4.0 CORING

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

9.4.1 Responsibilities

All coring requirements shall be detailed in the Drilling Program.

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

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

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

9.4.2 Coring Procedures

Preparation

The following preparations shall be made prior to cutting core:

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

9.4.2.1 Conventional Coring

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

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

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

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

5. The starting WOB must be applied slowly, and additional weight and RPM applied smoothly until the coring rate is maximised. Watch carefully for any indication of torque increase, ROP decrease or pump pressure change. The Driller shall inform the DSV of any change immediately. Changes may indicate the following:

   a) A pressure increase when coring may be due to plugging of the barrel, "O" ringing or plugging of the waterways of the corehead, or a change in formation.
   b) If the ROP is simultaneously reduced, the corehead is probably ringed or plugged. Continuation in this condition shall seriously damage the corehead.
   c) A decrease in pump pressure and ROP, accompanied by erratic torque readings, indicates jamming of the core. The barrel must be pulled out of the hole.

   Note: Barrel plugging can be checked by comparing the off-bottom pressure with that recorded prior to coring. If plugging is suspected the barrel must be pulled out of the hole.
   When making a connection or pulling off bottom, overpull may be seen as the core catcher grips the core. Pull to a maximum of 2,200 lbs. overpull, after allowing for drag. If the core fails to break, start circulating up to the maximum used while coring and hold the overpull until the core breaks.

6. Cut core until the barrel is full or becomes jammed, the end of the programd coring interval is reached, or cuttings indicate that the required section is cored.

7. Circulate bottoms up, condition the mud and POOH.

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

9.4.2.2 Oriented Coring

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

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

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

9.4.2.3 Coring Unconsolidated Formations

a) In unconsolidated formations, face discharge coreheads, fibreglass inner barrels, extended pilot shoes and special core catchers shall be used.

b) Circulating rates shall be the minimum required to keep the hole clean and sufficiently cool the corehead.

9.4.2.4 Rat-hole Coring

Coring a hole diameter smaller than the existing hole diameter is called rat-hole coring. When rat-hole coring, place existing hole sized stabilisers (i.e., 8 1/2" stabiliser if the existing hole size is 8 1/2") above the core barrel. On subsequent cores place these stabilisers correspondingly higher in the string, and place rat-hole sized drill collars and stabilisers above the core barrel.
No more than 36 m (120 ft) of rat-hole core should be cut without opening the hole.

9.4.3 Coring Assemblies

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

9.4.3.1 Coring Bits

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

9.4.3.2 Core Barrels

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

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

9.4.3.3 Drill String

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

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

9.4.4 Coring Fluids

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

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

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

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

9.4.5 Core Recovery and Packing

- A pre-job safety meeting must be held before pulling the core barrel through the rotary table to ensure that all personnel understand the job and potential hazards (e.g.trapped pressures and catcher failure, dropping core onto hand/feet).
- If there is any possibility of the core containing H2S, only the DSV, Driller, Coring Contractor, WGL and the minimum necessary number of crew shall be present when pulling the core barrel through the rotary table. If H2S is suspected, all personnel must wear breathing apparatus until it is confirmed that H2S is absent.
- The inner core barrel shall be retrieved/laid down only in single sections (10m).
- Every precaution shall be taken to ensure that inner barrel is protected during retrieval to avoid damaging the core.

9.4.5.1 Barrel Inspection on Core Recovery

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

9.4.5.2 Core Handling

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

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

9.5 MUD LOGGING

9.5.1 Responsibilities

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

9.5.2 Mud Logging Preparation

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

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

9.5.3 Monitoring

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

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

- Potential well control problems or drilling hazards.
- Any H2S detected.
- All unexplainable pit alarms and trend changes in the trip tank.
- Any significant increase in background gas or connection gas.
- Any significant divergence in mud density of the drilling fluid entering and leaving the well (when monitored).
- Any increase or decrease from the torque baseline (when monitored).
- An increasing or decreasing trend in standpipe pressure (when monitored).

9.5.4 Geological Service

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

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

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

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

9.6 DRILL STEM TESTING

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

9.6.1 Responsibilities

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

9.6.2 Standards

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

- The surface pressure rating of the wellhead shall be at least 10% higher than the maximum of the following conditions:

  Condition 1: SITHP for a gas filled tubing for the highest reservoir pressure to be tested.

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

9.6.3 Test Procedures and Guidelines

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

9.6.3.1 General Guidelines

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

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

Pre DST Checklist

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

Table 60. Pre test checklist.

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

9.6.3.2 DST Scheduling

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

9.6.3.3 Running Guidelines

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

9.6.3.4 Reverse Circulation / Pulling Procedures

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

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

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

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

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

9.6.4 DST Numbering Guidelines

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

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

CHAPTER 10
WELL CONTROL

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Continued over

10.1 OBJECTIVES

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

Ensure all regulatory requirements are met.

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

Note that well design is based on the following kick tolerance criteria:
12 ¼" intermediate hole, 30 bbl maximum influx (gas)
8 1/2" hole 30bbl maximum influx (gas)
6 1/8" hole 30bbl maximum influx (gas)
These volumes are easily detected with the current rig monitoring equipment.

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

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

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

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

10.2 RESPONSIBILITIES

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

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

Table 61. Responsibilities for Well Control

10.3 GENERAL STANDARDS

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

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

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

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

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

10.3.1 BOP Pressure Testing

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

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

Table 62. Frequency of BOP Pressure Testing

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

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

10.3.2 Diverter and BOP Equipment

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

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

10.4 EQUIPMENT STANDARDS

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

10.4.1 General BOP Arrangement

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

The BOP stack should comprise of at least:

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

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

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

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

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

NACE MR-01-75
API RP-53

Annular Preventers

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

Ram Preventers

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

Connections

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

10.4.2 Choke and Kill System

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

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

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

a) The assembly, connections, full opening valves, fittings, piping, etc., subject to well or pump pressure should be flanged, clamped or welded and have a rated working pressure at least equal to the rated working pressure of the BOP.

b) All components should be selected in accordance with applicable API Specifications, taking into consideration pressures, volumes, temperatures and conditions under which they may be operated (i.e. gas, oil, drilling fluid, hydrogen sulphide, the environment, etc.).

c) The choke manifold assembly and all choke lines shall be 3" nominal diameter or larger, have a minimum number of turns and be securely anchored. The dedicated kill lines shall be 2" nominal diameter or larger, and should be fitted with two valves and a non-return valve.

d) The choke control station, whether at the manifold or remote from the rig floor, should be as convenient as possible and should include all monitors necessary to furnish an overview of the well control situation. The ability to monitor and control from the same location such items as standpipe pressure, casing pressure, pump strokes etc., greatly increases well control efficiency.

e) Rig air systems should be checked to assure their adequacy to provide the necessary pressure and volume requirements for control of pneumatically or hydraulically operated chokes and valves. A redundant automatic choke control system, which may be manually operated, should be provided in the event that rig air becomes unavailable.

f) Initial testing of the entire choke manifold assembly to the same test pressure as the preventers should be performed when the blowout preventer stack is nippled up to the wellhead, and thereafter whenever the blowout preventers are tested.

g) Lines downstream of the choke manifold are normally not required to contain rated manifold working pressure, but should be tested during the initial installation.

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

10.4.3 Degasser

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

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

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

10.4.4 BOP Control Systems

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

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

The BOP closing systems shall be capable of closing

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

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

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

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

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

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

10.4.5 Drillstring BOP Valves

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

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

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

10.4.6 Kick Detection and Well Monitoring Equipment

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

Equipment	
Kick Detection Equipment	The following minimum kick detection equipment shall be available and fully operational: • Flowline monitor • Active pit volume monitors • Gas detection at header box (mud logger responsibility) • ROP recorder • Trip tank with a system for accurately monitoring returns during tripping
Mud Monitoring Equipment	All mud monitoring equipment (flo-show and PVT) shall be checked at various rates/volumes prior to drilling out casing and twice daily thereafter to ensure measurements indicated are correct and alarms are functioning.
Trip Tank	A trip tank shall be available and shall be complete with a mechanically operated indicator of the trip tank level visible from the Driller's position.
Gas Detection Equipment and Alarms	All gas detection equipment and alarms shall be functioning properly.

Table 63. Kick Detection and Well Monitoring Equipment

Continuous monitoring and recording of the following parameters shall be available on the drilling site for all wells:

- Active pit volume.
- Weight on bit and hook load.
- Standpipe pressure and choke pressure.
- Rate of penetration.
- Mud pump SPM.

Warning Signs - Possible Kick

One or more of the following warning signs may be associated with the initiation of a kick, all can be caused by other factors. All require an immediate flow check.

a. Increase in Pit Volume

An unexplained change in pit volume is the definitive indicator of a kick.

b. Increase in Relative Flow

This is an increase in return flowrate while the pumps are still running at a constant output. This is often the first positive indicator that a kick is occurring, however an influx from a low permeability formation may be difficult to identify.

c. Incorrect Hole Fill

If the volume of drilling mud required to fill the hole while pulling pipe is less than the calculated pipe displacement, formation fluids may be entering the wellbore.

d. Gas Cut Mud

An increase in mud gas level may signify that formation gas has flowed into the well. It may simply be as a result of drilling a formation with a high gas content, however this could lead to an undesirable reduction in mud weight.

e. Reduced Mud Weight

Mud weight reduction (or any significant change in other mud properties) may indicate a dilution of the mud by formation fluids - gas, oil or water.

f. Drilling Break

A drilling break (ROP change) is due to a change in formation drilling characteristics, and may indicate increases in formation porosity, permeability and pore pressure. Breaks may be positive or negative.

g. Decrease in Pump Pressure

A large influx of formation fluids, reduces the hydrostatic pressure in the annulus.The mud in the drill string can then U-tube into the annulus and the result is a reduction in pump load and pressure. The pressure reduction can cause the pumps to speed up. Normally if this indicator is seen, a serious kick has occurred and other indicators should be associated with it.

h. Increase in Hookload

When an influx displaces the drilling fluid in the wellbore there should be a reduction in the buoyancy of the drill string which should be seen on surface as an increase in the hookload. An increase in hookload is not a reliable method of detecting a kick because it requires a large influx of low density fluid to produce a measurable hookload increase.

Pore Pressure & Underbalance Indicators

a. Background Gas

Background gas (BG) is the mud gas content that enters the system when the formation in which it was formerly contained is removed as cuttings. It is unrelated to pore pressure and will occur even in overbalanced drilling conditions. High BG levels which do not decrease with circulation may indicate a steady flow of gas from an underbalanced, low permeability formation.

b. Connection Gas

Connection gas (CG) is caused by the temporary reduction in bottomhole pressure during a connection, due to the combined effects of ECD loss and the swabbing effect of moving the pipe. CG is characterised as a peak above background gas, which is recorded one lag time after the connection.

The presence of CG indicates pore pressure is less than drilling ECD, and greater than mud hydrostatic during swabbing. Increase in CG magnitude on successive connections is an indicator of increasing pore pressure.

c. Trip Gas

Trip gas (TG) is gas which entered the hole during tripping. Trip gas will be detected in the mud on circulating bottoms up after a round trip. An increasing trend in the magnitude of trip gasses may indicate that pore pressure is increasing. Significantly high Trip gas may indicate a close to balance situation exists in the hole.

d. Shale Cavings

Any cuttings that have not been created by bit action are termed 'cavings'. Pressure cavings are long, splintered and angular, and occur when overpressure causes the shale borehole wall to crack and burst into the well.

e. Decrease in Shale Density

Shale density normally increases with depth but this trend is reversed in abnormally pressured zones. The density of the cuttings is measured and plotted versus depth. Any deviation from the normal trend line may be interpreted as a pore pressure change.

f. Temperature Measurements

A change in temperature gradient is often associated with an abnormally pressured formation. The limitation of this method is that the mud temperature can usually only be measured on surface and is subject to external influences.

10.5 BOP SYSTEM TESTING AND INSPECTION

The BOP system shall be pressure tested according to the priciples below. Individual well programmes may require variations to test pressures.

- All BOP tests shall be tested to a low and high pressure. The actual pressure required will be given in the drilling programme. The criteria for the minimum pressure required for the high pressure test will be the greater of:
  a) Maximum surface pressure assuming gas from TD to surface.
  b) Surface pressure assuming gas from last casing shoe to surface with a 16 ppg fracture gradient at the shoe.
- All BOP system components shall be tested to a low pressure test of 200 psi prior to the required final high pressure test value.
- All BOP system components should be subjected to differential test pressures in the direction of pressure that will occur in service.
- The annular preventers should be pressure tested first, in order to allow them additional time to relax prior to pulling the test tool.
- Ensure valves are open downstream of the component being pressure tested.
- Maximise the number of components being tested on each test in order to minimise the number of tests.
- Ensure the downstream side of all preventer choke and kill valves are pressure tested.
- The criteria for a satisfactory test shall be a minimum of five minutes with a decline of less than 5% of test pressure.
- Test fluid volumes pumped and bled back must be carefully monitored and recorded. This is particularly important when testing against the casing pack-off to avoid pressuring the casing annulus and risking casing collapse.The control panels used should be alternated on each function and pressure test.
- All pressure tests shall be witnessed and signed by the DSV. Pressure tests shall be recorded on a chart recorder, reported on the Daily Drilling Report (Form F-301), the IADC Tour Sheet and the BOP Test Sheet (Form F-201).

10.5.1 Accumulator Function Test Requirements

- All Systems shall be cycled from the normal operating position and times recorded.
- Remote systems shall be checked, cycled, timed and recorded every day.
- Accumulator charging pump output will charge the accumulator system from precharge pressure to operating pressure in 15 minutes or less.
- Accumulator pump systems shall be functioned every tour while drilling by the driller.
- Rig air pressure systems shall be bled off every day to function test fail safe systems.
- Should any of the above tests indicate faulty equipment, the equipment must be repaired immediately and re-tested before drilling operations resume.

10.5.2 Maintenance and Inspection

The following general requirements for maintenance, inspection and testing of BOP and associated equipment shall be implemented as follows:

a) A BOP body pressure test shall be carried out once a year on the test stump, in accordance with the manufacturer's specification for such a test.

b) BOP's shall undergo a regular major overhaul and inspection, depending on the type of work and period in use. Periods between checks shall not exceed 5 years.

c) BOP hydraulic operating lines shall be tested to the maximum accumulator manifold pressure when newly installed and during every regular BOP stack test, by opening the Koomey KR bypass valve. The control lines to the annular preventer shall be tested once per well to the maximum operating pressure. The control lines are to be disconnected from the annular preventer in order to avoid damaging the annular preventer rubber.

d) Ensure the manufacturer's BOP operating manual is followed and no alterations are made to the BOP equipment without written consent from the manufacturer. Re-certification may be required after making equipment alterations.

e) Only genuine spares/replacement parts shall be used on BOP and associated equipment.

f) A maintenance schedule and checking procedures for BOP's shall be available on the drilling location and workshop.

g) Records of maintenance both scheduled and unscheduled shall be kept in a BOP history file at the Contractor's office. A copy of this file should also be kept at the rig.

10.6.0 WELL CONTROL DRILLS

Well control drills shall be initiated by the DSV and performed to ensure that the crews are adequately trained and prepared to implement well control procedures correctly. They shall only be conducted when they do not complicate ongoing operations. A kick should be simulated by manipulation of a primary kick indicator such as the tank level indicator or the flowline indicator.

The drills described below include the full sequence of shutting in a well, however the critical reaction time shall be recorded up to the point when the designated person is about to begin the closing sequence of the annular preventer(s).

It shall be necessary to repeat the drills each tour until the DSV is satisfied that the crews are adequately trained and responsive.

10.6.1 Well Control Drill Reporting

The following shall be recorded in the IADC tour report and the Daily Drilling Report:

- The types of drill conducted and the reaction time from the moment the kick is simulated until the crew is ready to start the closing procedure. The operation shall be recorded as "Well Control Drill".
- The total time taken to complete the drill.

10.6.2 Well Control Drills

The following sections describe the tasks required to perform four types of well control drills. These four drills are also displayed schematically in the Appendices at the end of this Chapter.

Note that the shut-in drill listed below assumes a hard shut-in technique for on-bottom drilling.

Kick Drill Condition 1 (On Bottom Drilling

1. Stop rotary.Raise kelly and slow down pump (Stop pump when lower kelly cock and first tool joint are above table)
2. Close annular preventer.
3. Open choke line (HCR valve).
4. Record drill pipe and casing pressures.
5. Record time to complete drill.

Kick Drill Condition 2 (While Tripping the Drill String)

1. Position upper tool joint above rotary table and set slips.
2. Install an inside BOP to the string; close the valve.
3. Close annular preventer.
4. Open choke line (HCR valve).
5. Install kelly and open inside BOP.
6. Record drill pipe and casing pressures.
7. Record time to complete drill.

Kick Drill Condition 3 (While Out of Hole)

1. Close blind rams.
2. Open choke line (HCR valve).
3. Record casing pressure.
4. Record time to complete drill.

Kick Drill Condition 4 (While Drill Collars are Adjacent to Preventers)

1. Position upper drill collar box at rotary and set slips.
2. Install an inside BOP to the string; close the valve.
3. Close annular preventer.
4. Open choke line (HCR valve).
5. Record drill pipe and casing pressure.
6. Record time to complete drill.

Note: If only 1 stand of drill collars remains to be recovered, the stand should be removed and the well treated as in Condition 3.

10.6.3 Routine Daily Precautions

Mud engineer to ensure adequate chemical supplies to control the well are available.

Slow Circulating rates (SCRs) for each pump must be taken (as a minimum) as shown below:

- Once per tour or at 150 m intervals during the tour.
- At bit and/or BHA changes.
- After significant changes in the drilling fluid density or rheology.
- Prior to drilling the casing shoe or transition zones.

Reporting shall be on the IADC and Daily Drilling Report and must include:

- A minimum of two pump rates.
- The SCRs chosen should not be less than 0.5 bbl/min and not greater than 4 bbl/min.
- The pressures must be recorded using the gauge to be used during well kill operations.
- SCRs shall be taken on all pumps and at the same rates.

10.6.4 Well Control Data Reporting

Basic well data must be recorded accurately at regular intervals and be easily available. This must include the following:

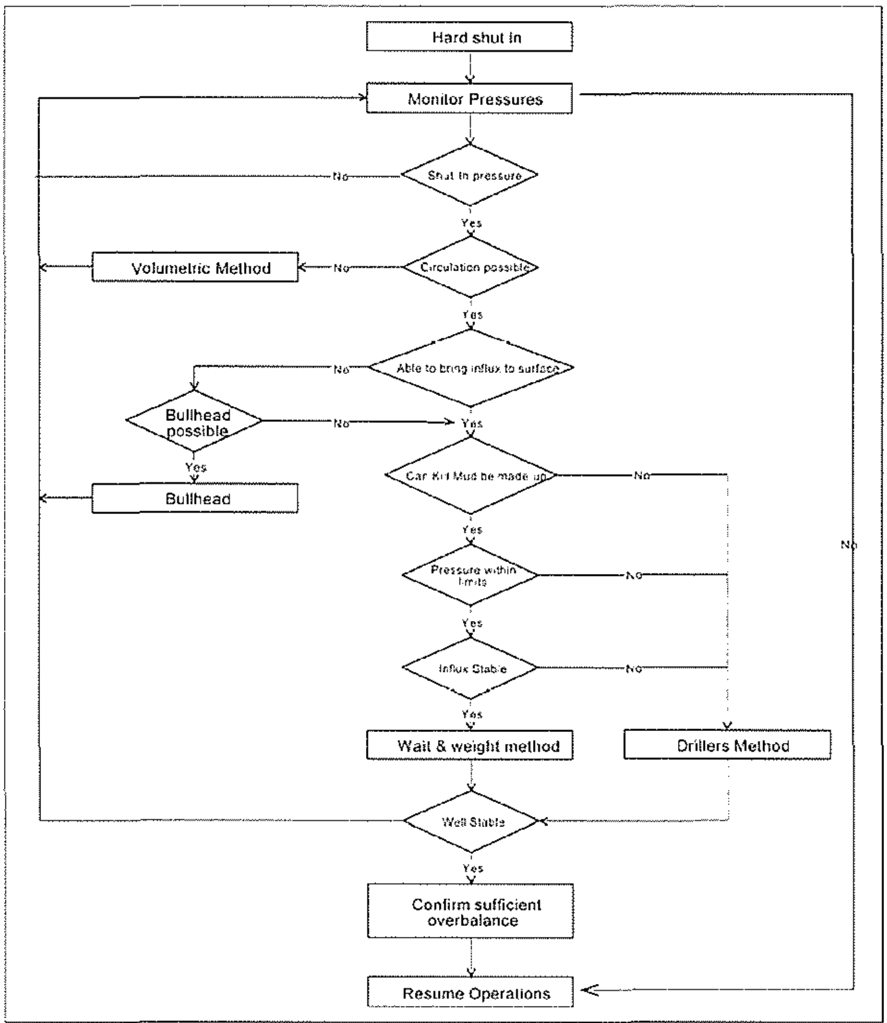
- SCR Pressure/Rate Data (see above).
- Leak Off Test as given in Chapter 10.9 of this Manual.
- Maximum Allowable Annular Surface Pressure , and see Appendix I, this Chapter.
- Completion of Killsheet by the DSV, Driller and Toolpusher.

10.7.0 WELL CONTOL PROCEDURES

- The preferred GSLM shut-in method of well control is 'hard' shut-in.
- The preferred method of Secondary Well Control is the Wait and Weight Method (Refer 10.7.3). Consideration should be given to using the drillers method (Refer 10.7.5) in situations where mud mixing and handling may be a problem.
- Other approved methods such as Bullheading and Volumetric Methods (see following text) shall only be utilised in special cases.

The appropriate method to be used is decided after consultation with the DSV and DM. The following flowchart shall be used as a guide.

Well Control Method Selection - Decision Analysis



Figur 10. Well Control Method Selection – Decision Analysis

10.7.1 Well Shut-in Procedures

The following sections describe the tasks required to perform three different shut-in procedures. These three procedures are also displayed schematically in the Appendices at the end of this Chapter.

Note: that the shut-in procedures listed below assume a hard shut-in technique.

Shut-in Procedure (While Drilling or Making Connection)

If well is flowing:

1. Stop rotary.
2. Raise kelly and slow down pump.(Stop pump when lower kelly cock and first tooljoint are above table).
3. Close annular preventer.
4. Open choke line (HCR valve).
5. Read and record:
   a) Shut-in Drill Pipe Pressure (SIDPP)
   b) .Shut-in Casing Pressure (SICP).
   c) Pit volume increase.
6. After recording shut-in pressures proceed to kill well as per Section 10.7.3.

Shut-in Procedure (Tripping with Drill Pipe) - Flow Chart

1. Position upper tool joint above rotary table and set slips.
2. Install an inside BOP to the string; close the valve.
3. Close annular preventer.
4. Open choke line (HCR valve).
5. Read off the SICP. If this value is less than 1000psi (or the MAASP, whichever is the lower pressure), reduce pressure on annular preventer, lubricate element and strip back in (if possible).
6. When the string is stripped in to maximum allowable SICP, stab in kelly and establish SIDPP, record new SICP.
7. After recording shut-in pressures proceed with well kill procedures.

Note: If it is not possible or feasible to strip drillstring back to bottom, the well may require to be killed using other techniques, the preceding may help in deciding which method to use (eg Bullheading: See Section 10.7.7).

Shut-in Procedure (Tripping with Drill Collars)

1. Position upper drill collar box at rotary and set slips.
2. Open choke line (HCR valve).
3. Close annular preventer if installed (if not installed, then add 1 joint or 1 stand of drill pipe to collars, and run back in hole; close pipe rams)
4. Install an inside BOP to the drill collar or drill pipe box.
5. Secure string at derrick floor.
6. Close inside BOP valve.
7. Shut in at choke.
8. Close manual valve upstream of choke.
9. After recording shut-in pressures proceed with well kill procedures.

Note:

a) If only 1 stand of drill collars remains to be recovered, the stand should be removed and the well shut in.

b) Drill collars could be dropped into the hole depending on potential severity of blowout.

10.7.2 Well Control Data and Calculations

The following data shall be monitored and recorded on the Well Control Operations log at the drill floor throughout a well kill operation.

- Times.
- The shut-in casing pressure (SICP).
- Shut-in Drill pipe pressure (SIDPP).
- Active pit volume.
- Description of events, including all pressures at one minute intervals until they have stabilised.

Well Calculations shall be made on the Killsheet and submitted to the DSV for approval. The DSV, Toolpusher, and Driller shall independently prepare a kill sheet for verification. These shall be used by the DSV to ensure accuracy of the well control calculations.

10.7.3 Wait and Weight Method (Well Kill Procedure)

The following well kill procedure is also given schematically in the Appendices at the end of this Chapter.

1. Zero stroke counter. Start the pump slowly while simultaneously opening the remote adjustable choke.
2. Increase pump speed to the selected kill pump rate while maintaining casing pressure constant.
3. When the pump is up to speed, read and record the Initial Circulating Pressure (Pic). In all cases use the actual Pic rather than the calculated value.
4. Maintain the drill pipe pressure as per the drill pipe pressure schedule on the Kill sheet. Maintain constant pump speed throughout circulation.
5. When the kill mud reaches the bit, maintain the drill pipe pressure constant at the Final Circulating Pressure (Pfc) by choke adjustment until kill mud reaches surface.
6. When kill mud reaches surface, shut down the pump and close the choke. Read and record SIDPP and SICP.
7. If drill pipe and casing pressures are recorded, bleed-off pressures to check for trapped pressure. If the well is not dead, resume circulation to ensure uniform kill mud throughout wellbore.If drill pipe and casing pressures equal zero, flow check through the choke line.
8. Circulate wellbore conventionally and add a suitable overbalance to the mud weight.

Note: If it is necessary to stop pumping at any time during the well circulation, immediately shut-in the well. To resume pumping, maintain kill line (wellhead) pressure constant while bringing the pump up to speed to account for choke line pressure drop. Pic shall be re-checked as per Step 3, and the drill pipe schedule adjusted if necessary.

10.7.4 Concurrent Method

The Concurrent Method is a variation of Wait and Weight Method. It is used when it is not possible to weight up the mud system to kill weight at once, but when the Driller's Method will result in an unacceptably high well bore pressure.

The mud weight is increased in stages until the well is full of kill weight mud, with each new weight being circulated all the way to surface. A new drill pipe schedule is constructed for each circulation as per the Wait and Weight Method.

10.7.5 The Driller's Method (Well Kill Procedure)

The Drillers Method is described below. The procedure has been subdivided into the procedure during the first circulation and the procedure for the second circulation.
The Driller's Method Well Control Schematic Procedures.

First Circulation

The procedure for the first circulation is as follows:

1. Zero stroke counter. Start the pump slowly while simultaneously opening the remote adjustable choke.
2. Increase pump speed to the selected kill pump rate while maintaining casing pressure constant to account for choke line pressure drop.
3. When the pump is up to speed read and record the Pic. The actual Pic should be used rather the calculated Pic.
4. When the influx has been circulated out of the well stop the pump and shut the well in at the choke. Read and record SICP and SIDPP. If the influx has been totally removed SICP should equal SIDPP.

Note: A kill graph is not required for the first circulation, since drill pipe pressure will be maintained constant at Pic after bringing the pump up to speed. Pic should be estimated prior to commencing circulation:

Pic = PSCR + SIDPP (psi)

Second Circulation

The procedure given below is also shown schematically in the Appendices at the end of this Chapter.

Note: The standpipe pressure at the start of the second circulation (Pic) may be taken as the actual circulating pressure at the end of the first circulation.

1. Prepare Kill Graph. The circulating pressure when the kill mud reaches the bit shall be calculated as follows:

$$P_{fc} = P_{ACTUAL}\ x\ \frac{\text{Kill Mud Weight}}{\text{Original Mud Weight}}\ (psi)$$

The standpipe pressure versus volume pumped or time should be plotted. Standpipe pressures should include a safety margin (use 150psi) to allow for choke operator reaction time.

The graph shall be prepared as follows:

i. Plot the initial standpipe pressure (Pic) at the start of the second circulation.
ii. Plot the standpipe pressure when kill mud has reached the bit (Pfc)
iii. Connect the two points with a straight line. This line represents the standpipe pressure whilst pumping the kill mud from the surface to the bit.

1. Start well killing procedure by zeroing the stroke counter.
   Start the pump slowly while simultaneously opening the adjustable choke.
2. Increase pump speed to the selected kill pump rate while maintaining casing pressure constant to account for choke line pressure losses.
3. After the pump is up to speed, read and record the Pic . The actual Pic should be compared to the calculated value, and if required, adjustment made to the drill pipe pressure schedule to account for any differences between the two values.
   In all cases, use the actual Pic rather than the calculated value.
4. Maintain the drill pipe pressure as per the drill pipe pressure schedule.
   Maintain constant pump speed throughout circulation.
5. When the kill mud reaches the bit, maintain the drill pipe pressure constant at the Pfc by choke adjustment until kill mud reaches surface.
6. When kill mud reaches surface, shut down the pump and close the choke. Check drill pipe and casing for pressure.If drill pipe and casing pressures are recorded, bleed off pressures to check for trapped pressure.If the well is not dead, resume circulation to ensure uniform kill weight mud throughout wellbore.
7. If drill pipe and casing pressures equal zero, flow check through the choke line.
8. Circulate wellbore conventionally and add a suitable overbalance to the mud weight.

Note: If it is necessary to stop pumping at any time during the well circulation, immediately shut-in the well. To resume pumping, maintain kill line (wellhead) pressure constant while bringing the pump up to speed to account for choke line pressure drop. Pic shall be re-checked as per Step 3, and the drill pipe schedule adjusted if necessary.

10.7.6 Static Volumetric Method (Well Kill Procedure)

The Static Volumetric Method is used to control rising well pressures due to a migrating influx. It is a constant bottomhole pressure method. It can only be used if the influx is migrating. It is an alternative to a circulation kill method which may be used in the following circumstances:

- Drill string out of hole.
- Drill string cannot be stripped to bottom.
- Washed out or parted drill string.
- Plugged bit.

Static Volumetric Control Procedure (Casing Pressure Method)

The procedure given below is also shown schematically in the Appendices at the end of this Chapter.

1. Prepare the Volumetric Control Worksheet for the kill operation. The influx migration and hydrostatic pressure equivalent shall be determined as shown in the table below.

Calculation	Equation	Abbreviations
Influx Migration Rate	$MR = \frac{(P2 - P1) \times 19.25}{MW \times T}$	MR = Migration Rate up constant cross Section annulus (ft/hr) P1 = Surface pressure at start of time Interval T (psi) P2 = Surface Pressure at end of time Interval T (psi) MW = Mud weight (ppg) T = Time interval between Pressure Readings (hours) HPE = Hydrostatic Pressure Equivalent of 1 barrel of mud in the annulus (psi) dh = Hole or Casing ID (in) do = Drill String OD (in)
Hydrostatic Pressure Equivalent	$HPE = \frac{53.44 * MW}{(dh^2 - do^2)}$	

Table 64. Influx Migration Rate and Hydrostatic Pressure Equivalent Calculations

2. Allow casing pressure to increase by an overbalance margin plus an operating margin. The suggested value for each of these margins is 100psi.
3. Bleed off a volume of mud from the annulus which is equivalent to the operating pressure margin. Maintain the casing pressure constant as the mud is bled from the well. This will be a very slow process because the rate of expansion is governed by the migration rate calculated in Step 1. This will result in the formation remaining over- balanced by the overbalance margin. Use a manual choke to ensure adequate control.
   Record all volumes and pressures on the Volumetric Control Worksheet.
4. Repeat steps 2 and 3 above. Do not vent gas when the influx reaches surface as the bottomhole pressure may decrease and a further influx may be taken.
5. Prepare high density mud to pump into the well. Calculate the hydrostatic pressure equivalent for one barrel of lubricating mud in the annulus using the same equation outlined in Step 1.
6. Line up to pump lubricating mud down the kill line.

7. Pump lubricating mud into the well until pump pressure reaches a predetermined limit based on MAASP (Maximum Allowable Annulus Surface Pressure).
   Record volume pumped.
8. Allow the lubricating mud to fall through the influx as the well is left static.
9. Bleed gas from the well to reduce the casing pressure by an amount equivalent to the hydrostatic pressure of the lubricating mud pumped into the well. Ensure returns are lined up through the poor boy degasser and the volume of any mud bled back is recorded. Shut-in immediately when mud returns are noted when bleeding off.
10. Repeat Steps 5 and 6 until all gas has been vented from the well.

Static Volumetric Control procedure (Drill Pipe Pressure Method)

This procedure shall only be used in the following circumstances:

- Pipe on bottom.
- No drill string float (ported or un-ported) installed.

The procedure given below is also shown schematically in the Appendices at the end of this Chapter.

1. Determine the migration rate as shown in the table above.
2. Allow the drill pipe pressure to build up by an operating margin of c. 100-200psi overbalance margin. This will depend on the MAASP.
3. Bleed mud from the choke manifold until the drill pipe pressure has reduced to the original stabilised shut-in value plus the overbalance margin.
4. The mud must be bled very slowly; the delay time may be considerable before drill pipe response is seen.
5. It is essential that the bottomhole pressure is not allowed to fall below formation pressure.
6. Continue Steps 2, 3, 4 and 5 until the influx has migrated to surface. Do not bleed off gas.

10.7.7 Bullheading

Bullheading can be considered when:

- Large gas influx that will result in an excessive volume of gas or excessive pressure at the surface if circulated out.
- Pipe is off bottom and cannot be stripped in.
- No pipe in the hole.

Factors which may affect the feasibility or success of bullheading:

- Discrete or strung out influx. An influx sustained while drilling may be contained in a large mud volume that will be difficult to squeeze away.
- MAASP due to formation fracture pressure and equipment rating.
- Formation permeability.

Bullheading Procedure

The procedure given below is also shown schematically in the Appendices at the end of this Chapter.

1. Assess the migration rate as described in Section 10.8.6
2. Calculate MAASP for the current mud weight.
3. Establish injection pressure by pumping down the annulus at a slow rate.
   Keep pump rates constant and plot the injection pressure versus the volume.
4. Do not exceed MAASP.
5. If injection pressure continues to increase, stop pumping and observe.
   A decrease in pressure indicates successful bullheading.
6. Continue pumping to over-displace the top of the influx to TD by 50%.
7. Shut down and observe the well.
8. Raise mud weight (if necessary), if possible circulate using Wait and Weight Method until annulus is clear of influx.

10.7.8 Stripping

The procedure described in this section is the Combined Stripping and Volumetric Technique that maintains constant bottomhole pressure while the pipe is stripped through the annular. The principle used to accomplish this is a volume balance of the wellbore; for every barrel of pipe stripped in the hole a barrel of mud is bled off.

The following text summarises the calculations performed prior to stripping in. This procedure is also shown schematically in the Appendices at the end of this Chapter.

Maintaining Constant Bottom Hole Pressure

The pipe volume added to the well will increase the bottomhole pressure if mud volume is not bled off. Bottomhole pressure will also increase due to influx migration during the time period that stripping operations are being conducted. As the BHA enters the influx, an additional increase in bottomhole pressure can occur. These effects must be accounted for in order to maintain constant bottomhole pressure.

Determine Pipe Volume Effect

1. Calculate the pipe volume (per stand of pipe stripped in) as follows:

$$V = LS\ (Ddp + Cdp)$$

Where
V = Volume per stand (bbls).
LS = Average stand length (ft).
Ddp = Drill pipe displacement(bbls/ft).
Cdp = Drill pipe capacity (bbls/ft).

2. When each stand has been stripped in, bleed off the calculated required volume of mud from the annulus (i.e. during connection). This method can provide a clearer indication of when the BHA enters the influx.

   Note: A float must be used and the pipe filled when RIH.

   Alternatively, it may be preferred to bleed off volume as the pipe is being run, to maintain a more constant pressure regulation process, or if the pressure increase resulting from adding one stand approaches or exceeds MAASP.

3. If pipe is being stripped out of the hole, the required volume of mud should be added continuously as the pipe is being pulled to ensure the bottomhole pressure does not drop and thereby allow additional influx to enter the wellbore.

Determine Influx Migration Effect

When stripping operations take a significant time to complete, influx migration effects must be considered. Usually, the volume of mud to be bled for influx migration is small relative to the volume bled off to compensate for the addition of pipe into the hole.

Influx migration can be detected by:

- A gradual increase in surface pressure even though the correct volume of mud is being bled from the well.
- Surface pressures increasing when the pipe is stationary.

The volume of mud to be bled-off for influx migration can be calculated using the Hydrostatic Pressure Equivalent formula given in Section 10.7.6

Determine Effect of BHA Entering Influx

When the BHA is run into the influx, the surface pressure will increase at a higher rate than prior to entering the influx. This is due to the displacement of the influx around the BHA extending the influx height and hence lowering the total hydrostatic pressure in the annulus.

Whilst balancing formation pressure, the surface pressure therefore increases.
It is very important to recognise this effect and to ensure that the casing pressure is not bled off to compensate for the increase in pressure.

The maximum possible pressure increase due to the BHA entering the influx shall be calculated as follows:

$$\text{PMI} = \frac{(53.44)(MW-IFG)}{dh^2} V \left\{ \frac{dh^2}{dh^2 - do^2} - 1 \right\}$$

Where	PMI	= Maximum Pressure increase (psi).
	MW	= Mud weight equivalent (ppg)
	IFG	= Assumed influx fluid density (ppg)
	V	= volume per stand of pipe (Bbls) as calculated above
	dh	= Hole size (in)
	do	= BHA OD (in)

Stripping Procedure

This procedure is also shown schematically in the Appendices at the end of this Chapter.

1. Install inside BOP valve above drill pipe stab-in valve. Open stab-in valve.
2. Reduce annular closing pressure to the recommended pressure for stripping pipe at the actual casing pressures. Allow a slight leakage through the preventer while stripping.
3. The pipe should be slowly lowered through the annular while the annular surface pressure is accurately monitored. Reduce running speed when passing tool joints through the annular.
4. Bleed the required volume of mud from the well during each connection unless MAASP pressure limitations dictate that it be bled more frequently. Complete the Stripping Worksheet for each stand run and each time volume is bled.

   Note: Maintain an overbalance of 50 to 200psi at all times while stripping, unless formation integrity will not be able to take such an overbalance.
5. Fill the pipe every five stands with original weight mud.
6. Strip to bottom or desired depth to kill well.

Changing Rams etc. while stripping

The combination wear bushing/test tool designed for the compact wellhead system is capable of being hung off on the wear bushing. In the event of a serious leak in the annular preventer or pipe rams therefore, it is possible to:

1. Strip in the combination tool using the annular and pipe preventer.
2. Land out on the wear bushing.
3. Back out the running string above the combination tool (this connection must be made up “soft”).
4. Close the blind rams above the tool.
5. Effect necessary repairs while monitoring/control pressures.
6. Retrieve the combination tool and strip out of hole.
7. Resume operations.

10.8 WELL CONTROL PROBLEMS

Conventional well control procedures are based upon the assumption that all of the well control equipment operates as designed and the wellbore is able to withstand the imposed pressures. Mechanical problems and formation fracturing, however, occurs occasionally during well killing operations causing complications with conventional procedures.

Careful consideration must be given to the available well data before selecting an alternative procedure. The figure below outlines the possible cause of problems for several unexpected changes in surface measurements.

	DRILL PIPE PRESSURE	CASING PRESSURE	DRILL STRING WEIGHT	PIT LEVEL	PUMP S.P.M.
LOSS OF CIRCULATION	⬇	⇩	⬆	⬇	⇧
CHOKE PLUGS	⬆	⬆	NO CHANGE	⇩	⇩
BIT NOZZLE PLUGS	⬆	NO CHANGE	NO CHANGE	NO CHANGE	⇩
BIT NOZZLE WASHES OUT	⬇	NO CHANGE	NO CHANGE	NO CHANGE	⇧
PUMP VOLUME DROPS	⇩	⇩	NO CHANGE	NO CHANGE	NO CHANGE
HOLE IN DRILL STRING	⬇	NO CHANGE	NO CHANGE	NO CHANGE	⇧
GAS FEEDING IN	NO CHANGE	⇧	⇧	⬆	⇧
CHOKE WASHES OUT	⇩	⬇	NO CHANGE	⬆	⇧
GAS REACHES SURFACE	NO CHANGE	⬆ THEN ⬇	⇩	⬇	NO CHANGE
SYMBOLS:	⇧ INCREASE	⇩ DECREASE	■ MAJOR	□ MINOR	

Figure 11. Well Control Problem Indicators

10.8.1 Well Control in Horizontal Wells

Although the kill calculations are identical for straight, deviated and horizontal wells (true vertical depths used in all cases) and the well control procedures are based on the same principles, these considerations should be implemented during both the planning and operational phases of a horizontal drilling programme.

1. <u>Tripping</u>

In general, the bottom hole assemblies used to drill horizontal wells are not as likely to cause swabbing as those run in vertical wells. However, substantial reservoir intervals may be exposed, increasing the potential for swabbing and making induced kicks greater than in a vertical well.

Extreme caution shall be exercised when returning to bottom following a trip. The horizontal section of the wellbore could be partially or completely filled with reservoir fluids despite the well being static (i.e. not flowing). It is therefore recommended that bottoms up be circulated through the choke manifold and degasser prior to drilling ahead.

2. Influx Volume and Nature

In the event of a kick in a horizontal well it is virtually impossible to determine the nature of the influx (i.e. oil, gas, water) due to equivalent shut in drill pipe and casing pressures. It may be difficult to validate data obtained during a kick and hence it is recommended to assume a gas influx at all times.

3. Productivity

The economic rationale responsible for the implementation of a horizontal drilling programme should be kept in mind when considering well control issues. The enhanced productivity and amount of reservoir section exposed tend to increase the rate of influx. Rig personnel should be particularly cognisant of well control procedures while drilling through the pay zone, especially if drilling at the balance point with non-damaging brines. Well control should never be ignored due to directional control problems.

10.8.2 Gas Hydrates

Gas hydrates can present serious problems during well control operations. Gas hydrates are complex crystalline structures of hydrocarbons and water having the appearance of hard snow. They can form at temperatures above the normal freezing point of water under certain pressure conditions. This formation process is accelerated where there are high gas velocities, pressure pulsations or other agitation's which cause mixing of the hydrate components.

The conditions for hydrate formation can be predicted. These pressure and temperature conditions can exist in a well control operation where low geothermal gradients exist, or downstream of a pressure drop in the system, i.e. choke. This can result in plugging of surface lines downstream of the choke.

Prevention of gas hydrates can be accomplished by maintaining pressures and temperatures outside the hydrate range, or by suppressing the hydrate formation temperature by injecting glycol into the gas stream. In well control operations pressure or temperature control methods for gas hydrate prevention are usually not possible, therefore use of glycol injection is recommended.

A gas hydrate contingency plan should be formulated for all wells where the potential exists for gas hydrate formation. The plan should provide a method of injecting glycol at the BOP stack.

A suggested method of accomplishing this is to pump glycol down the kill line with the cement unit and slowly injecting it into the well as the gas approaches surface and enters the choke line.

10.8.2 Cement Plug

If the well can not be controlled by conventional means it may be necessary to cement off the over-pressured zone.The cement slurry design should take account of the following factors:

- Spacer type and volume must prevent contamination during displacement.
- Surface lines must be free of potential contaminants.
- Gas channelling must be minimised by application of appropriate cement recipe technology.
- Slurry volume must be sufficient to allow for displacement into the formation.
- Slurry density must be sufficient to provide overbalance during displacement

The use of cement offers little chance of recovering the drillstring once cement is displaced up the annulus, particularly around stabilisers in the BHA. It must also be considered that there is a poor chance of achieving adequate cement isolation in the annulus between the BHA and hole. In addition, cementing will often result in the bit nozzles becoming plugged preventing further cementing attempts without resorting to perforating the drill pipe. Consequently cement plugs should be considered a last resort.

10.8.4 Barite Plug

This is a mixture of barite and water or diesel. The objective is to utilise the rapid settling effect of the barite in water, in the absence of any viscosifier, to rapidly form an impermeable barrier to flow.

The following is a guide to the typical recipes for 1 barrel of barite plug. The mud engineer should perform pilot testing prior to pumping:

Required Density (ppg)	Volume of Freshwater Required (bbl)	Amount of Barite Required (lbs)
17.9	0.642	530
20.0	0.560	643
21.0	0.528	695
21.93	0.490	740

Table 65. Barite Plugs, Barite-Water Mix for Water Based Muds

Lignosulphonate thinner at 0.4ppb and caustic should be added to keep the barite particles separate.

Displacement Procedure

1. The barite slurry should be mixed by adding the barite to previously prepared water and thinners.
2. The slurry must then be pumped immediately unless continuous agitation is possible.
3. The slurry should be pumped at a higher rate than the kick rate and no less than 10 bbl/min with both the cement unit and rig pump tied into it.
4. After the plug has been displaced, it should be verified that flow has been stemmed by shutting in the well and observing pressures.
5. If the flow has stopped and a second plug is not required then the pipe will be pulled above the plug and circulated clean.

10.9 FORMATION INTEGRITY TESTS

The hesitation method shall be used for the conduct of all Formation Integrity Tests. This involves pumping a small amount, waiting for the pressure to stabilise before repeating the process until the maximum test pressure is achieved. The test pressure shall be limited to a maximum pressure that does not exceed the lowest of the following:

- Actual leak-off pressure.
- The pressure specified in the Drilling Programme (typically the pressure required to give required kick tolerance or 80% of casing burst pressure).
- The wellhead test pressure.
- The BOP test pressure.
- A maximum pressure of 0.8 psi/ft at the casing shoe.

10.9.1 Responsibilities

All responsibilities for Formation Integrity Testing are given in Section 10.2

10.9.2 Testing Preparation

The following equipment is recommended for execution of a Formation Integrity Test, for accuracy and control:

- Pumping unit with tanks calibrated in ¼ barrel increments.
- Calibrated gauges covering anticipated pressure ranges mounted on a manifold.
- Chart recorder.

10.9.3 Test Procedure

The following procedure shall be adhered to when performing a Formation Integrity Test:

1. Drill out cement plus 3 m of new formation.
2. Circulate clean to a balanced mud weight (use old mud from previous section).
3. Pull the bit back in casing shoe.
4. Make sure the hole is filled up and close the annular BOP (Hydril) around the drill pipe.
5. Rig up the pump to the drill pipe. Use a pressure gauge of appropriate range (0 - 1,500 psi.), mounted at the pump unit manifold.
6. Slowly pump mud until pressures begin to increase. Volume pumped will start from this point.
7. Pump 0.125 - 0.25 bbl and wait for 2 minutes or the time required for the pressure to stabilise in the case this takes longer.
8. Record the volume pumped, and the bleed back stabilised pressure.
9. Repeat items 6 & 7 and plot pressures versus cumulative mud volume
10. Continue procedure until either the final stabilised pressure, after the waiting time, deviates from the expected pressure from the plot or the required maximum pressure is reached.
11. Keep well closed in to verify that a constant pressure has indeed been obtained.
12. Release pressure and record volume recovered in tank.

10.9.4 Calculations

Formation Intake Gradient (FIG)

$$FIG = \frac{LOP + (CSD \times MG)}{(CSD - RKBE)} \quad psi/ft$$

Effective Mud Gradient (EMG)

$$EMG = \frac{LOP + (CSD \times MG)}{CSD} \quad psi/ft$$

Maximum Allowable Annular Surface Pressure (MAASP)

$$MAASP = LOP - (CSD \times MG) \quad psi$$

Formation Breakdown Pressure (FBP)

$$FBP = LOP + (CSD \times MG)$$

Where:

Where:	LOP	=	Leak-Off Pressure (psi), surface pressure recorded during the test
	CSD	=	Shoe Depth of last casing set (TVD ft RKB)
	MG	=	Mud Gradient (psi/ft)
	RKBE	=	Rotary Kelly bushing elevation above ground level (ft)

APPENDIX 1: GENERAL WELL CONTROL FORMULAE

1. The Formation Pressure (P_0)

$$P_0 = P_{dp} + (D_h \times \rho_1) \text{ psi}$$

Po = Formation Pressure (psi)
Pdp = Shut in drill pipe pressure (psi)
Dh = Depth of hole (ft)
p_1 = Formation pressure gradient (psi/ft

2. The new mud gradient to balance P_0 (ρ_2)

$$\rho_2 = P_0 \div D_h \text{ psi/ft}$$

3. The height of the influx (h_{inf})

$$h_{\inf} = V_{\inf} \div CAP_{ann} \text{ ft}$$

Vinf = Volume of influx (bbl)
CAPann – Annular capacity (bbl/ft)

4. The gradient of the influx (ρ_{inf})

$$\rho_{\inf} = \rho_1 - (P_{ann} - P_{dp}) \div h_{\inf} \text{ psi/ft}$$

Pann = Shut in casing pressure (psi)

5. Type of influx

$\rho_{\inf} \langle$ 0.2 psi/ft is gas

$\rho_{\inf} \langle$ 0.35 - 0.39 psi/ft is crude oil

$\rho_{\inf} \langle$ 0.433 psi/ft is water

$\rho_{\inf} \langle$ 0.433 - 0.465 psi/ft is salt water

6. Volumes

Contents of string

$$V_{str} = CAP_{dp} \times (D_h - L_{dc}) + CAP_{dc} \times L_{dc} \text{ bbls}$$

Vstr = Volume of string (bbl)
CAPdp = Capacity of dp (bbl/ft)
Ldc = Length drill collars (ft)
CAPdc = Capacity of dc (bbl/ft)
Ldc-oh = Length dc in oh (ft)

Contents of annulus open hole section

$$V_{dc-oh} = CAP_{dc-oh} \times L_{dc-oh} \text{ bbls}$$

Vdc-oh = volume between oh and dc (bbl)
CAPdc-oh = Capacity between dc and oh (bbl/ft)

$$V_{dp-oh} = CAP_{dp-oh} \times L_{dp-oh} \text{ bbls}$$

Vdp-oh = volume between oh and dp (bbl)
CAPdp-oh = Capacity between dp and oh (bbl/ft)
Ldp-oh = Length dp in oh (ft)

Contents of annulus casing section

$$V_{csg-dp} = CAP_{csg-dp} \times D_{csg} \text{ bbls}$$

Vcsg-dp = volume between csg and dp (bbl)
CAPcsg-oh = Capacity between csg and oh (bbl/ft)
Dcsg = Depth of casing (ft)

7. Pre kick calculations

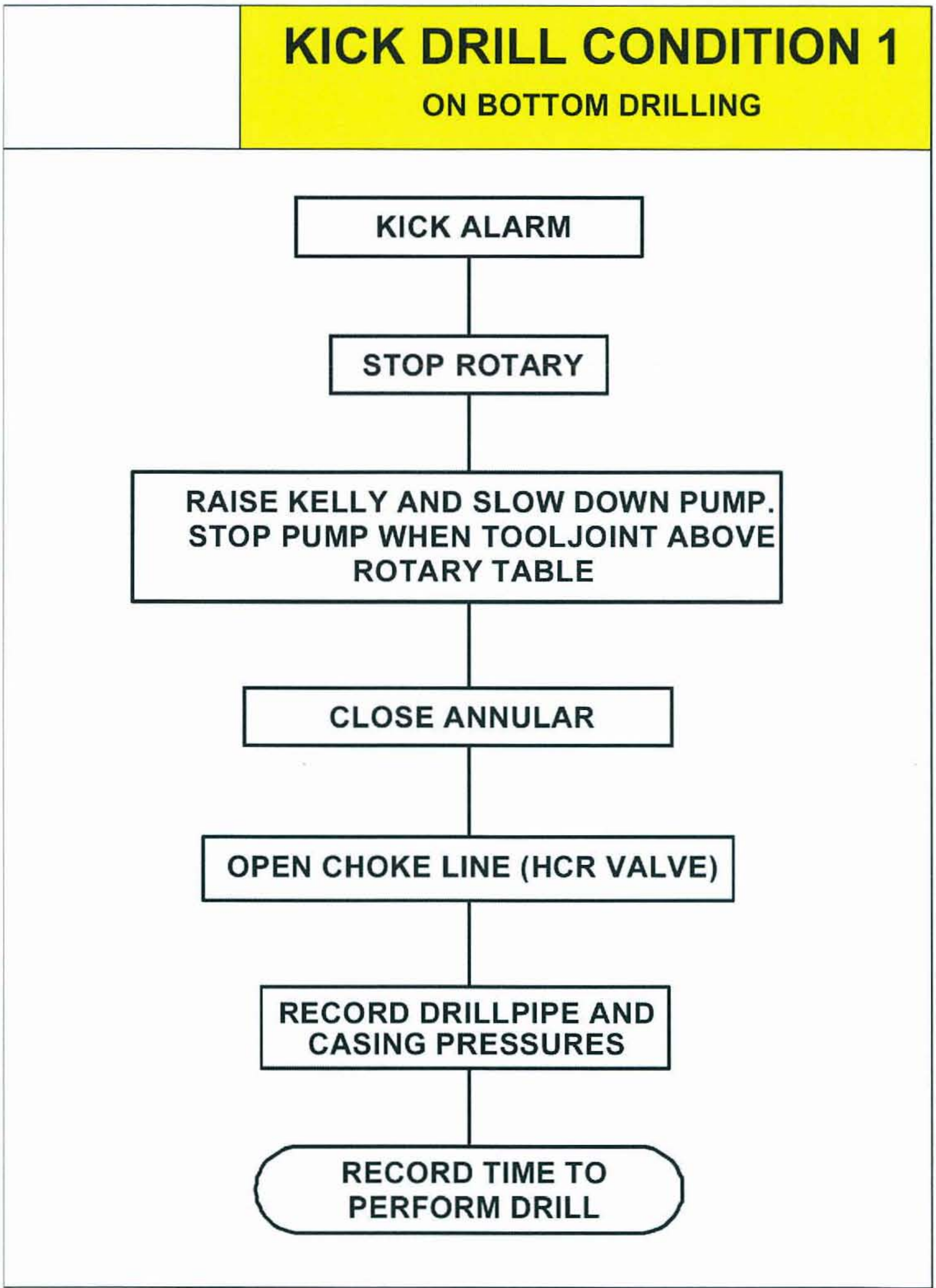
1. MAASP $= (\rho_{fs} - \rho_1) \times D_{csg}$ psi
2. $CAP_{str} = 9.7138 \times \varnothing^2_{id\,pipe} \times 10^{-4}$ bbls/ft

   Note: 1) $\varnothing_{id\,pipe}$ in inches. 2) $CAP_{str} = CAP_{dp} + CAP_{dc}$ + etc.
3. $CAP_{ann} = 9.7138 \times (\varnothing^2_{id\,hole} - \varnothing^2_{id\,pipe}) \times 10^{-4}$ bbls/ft

   Note: 1) $\varnothing$ in inches 2) $CAP_{ann} = CAP_{dc\text{-}oh} + CAP_{dp\text{-}oh} + CAP_{dp\text{-}csg}$ + etc.

Appendix II: Well Control Schematic Procedures

This Chapter contains the following schematic representations of the key well control procedures described in this Manual:



Fgure 12. Kick Drill Condition 1 (On Bottom Drilling)

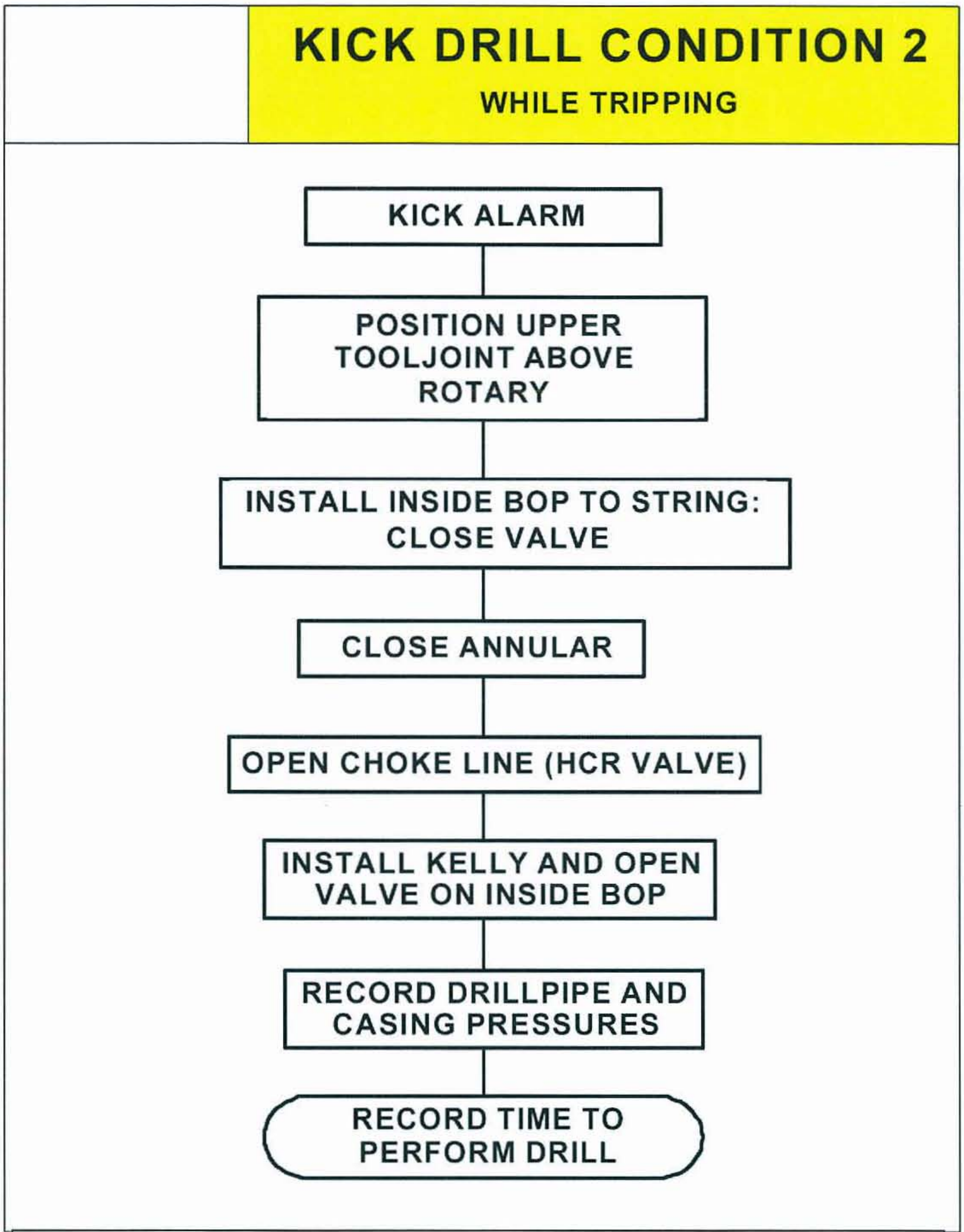


Figure 13. Kick Drill Condition 2 (Tripping)

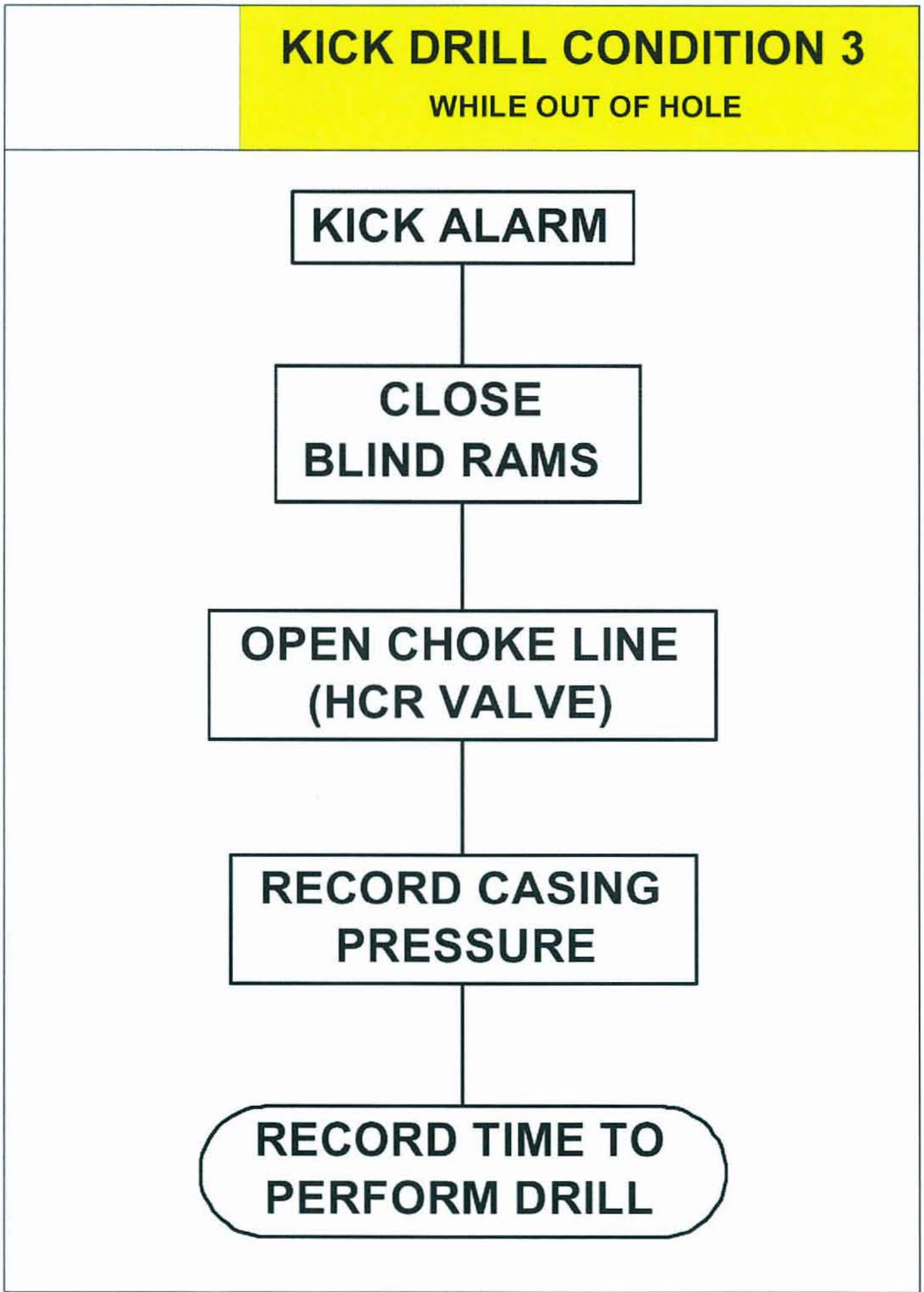


Figure 14. Kick Kill Condition 3 (Out of Hole)

KICK DRILL CONDITION 4

WHILE DRILL COLLARS ARE ADJACENT TO PREVENTERS

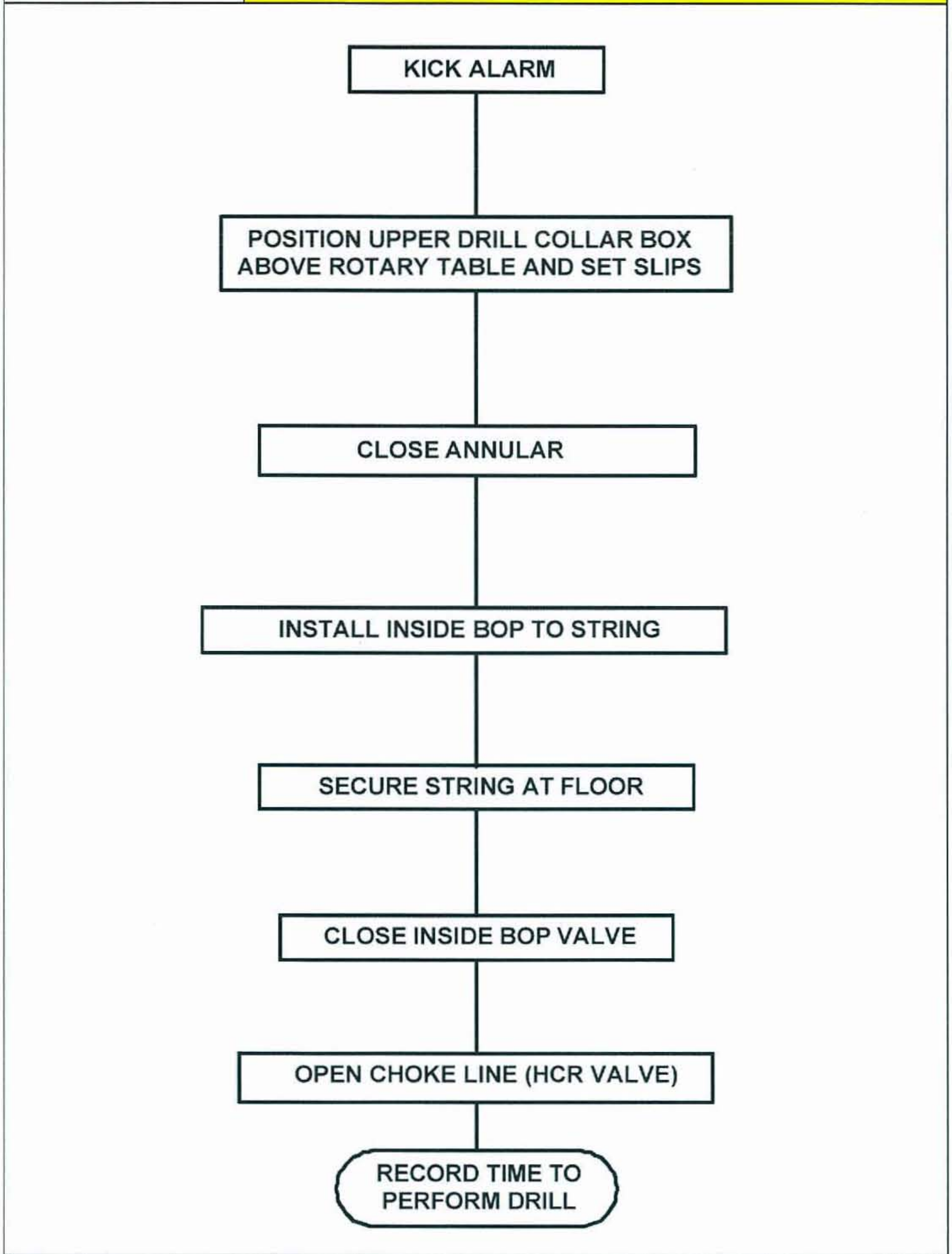


Figure 15. Kick Drill Condition 4 (Drill Collars Adjacent to Preventors)

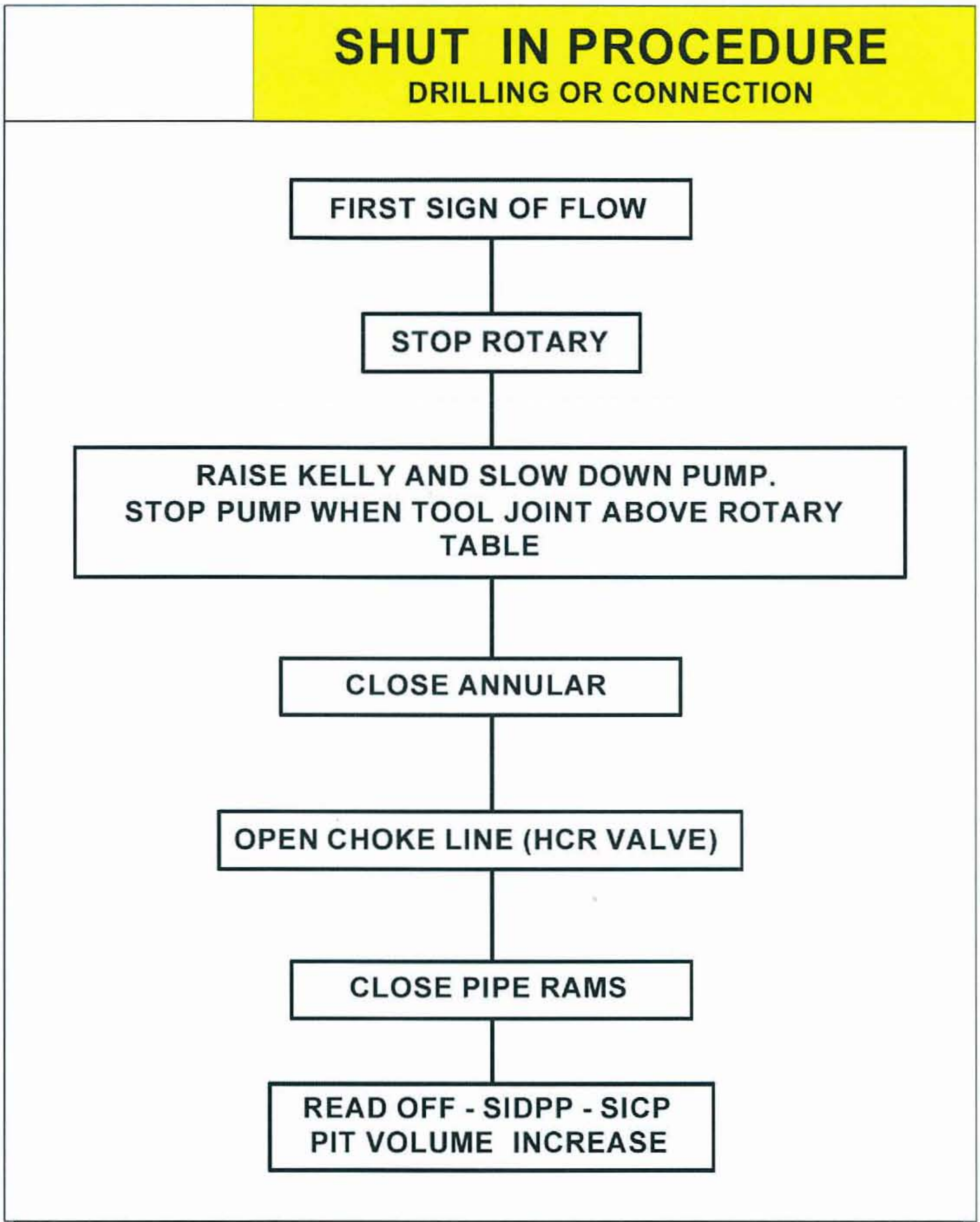


Figure 16. **Well Shut-in Procedure (Drilling or Connection)**

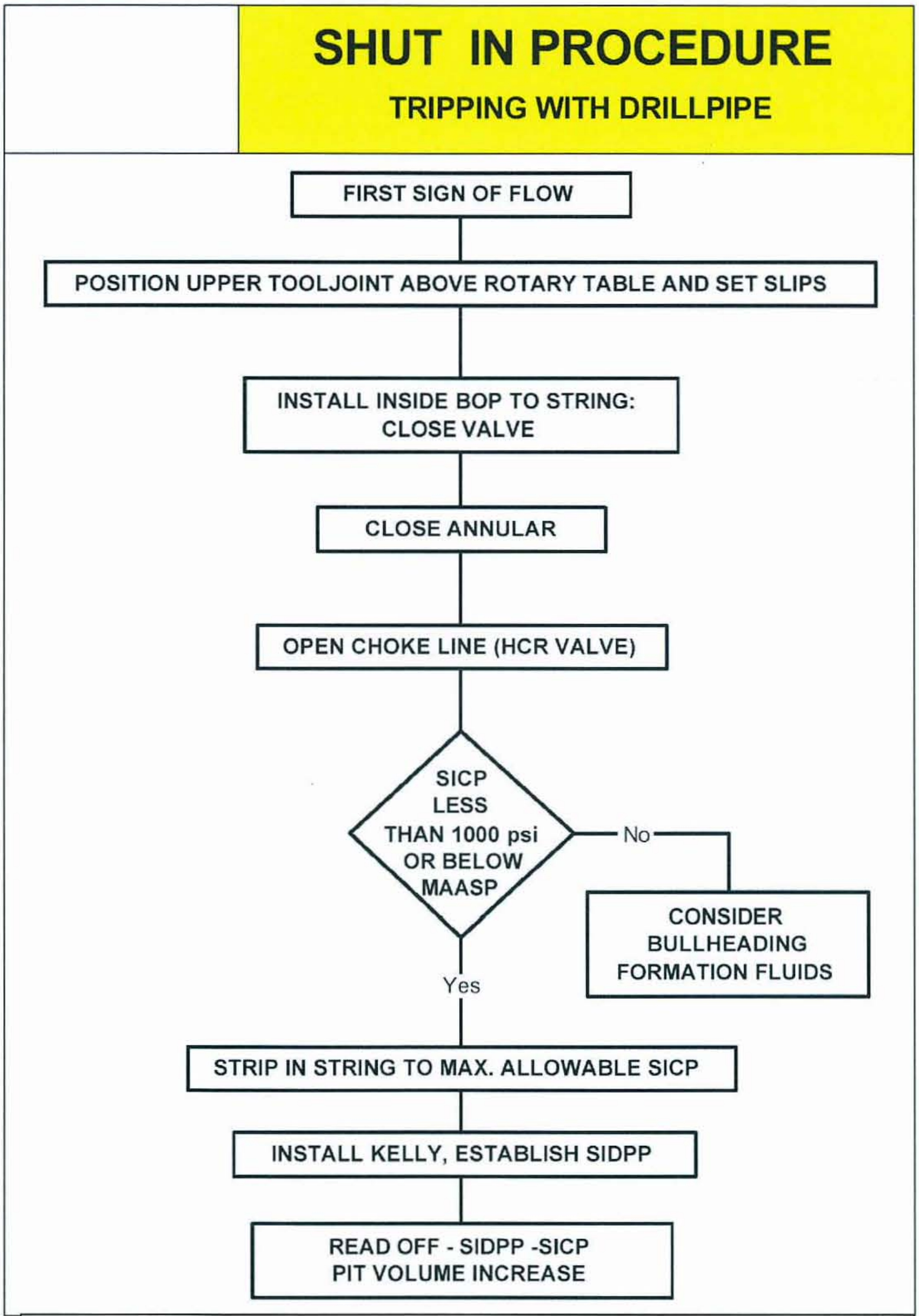


Figure 17. Well Shut-in Procedure (Tripping with Drill Pipe)

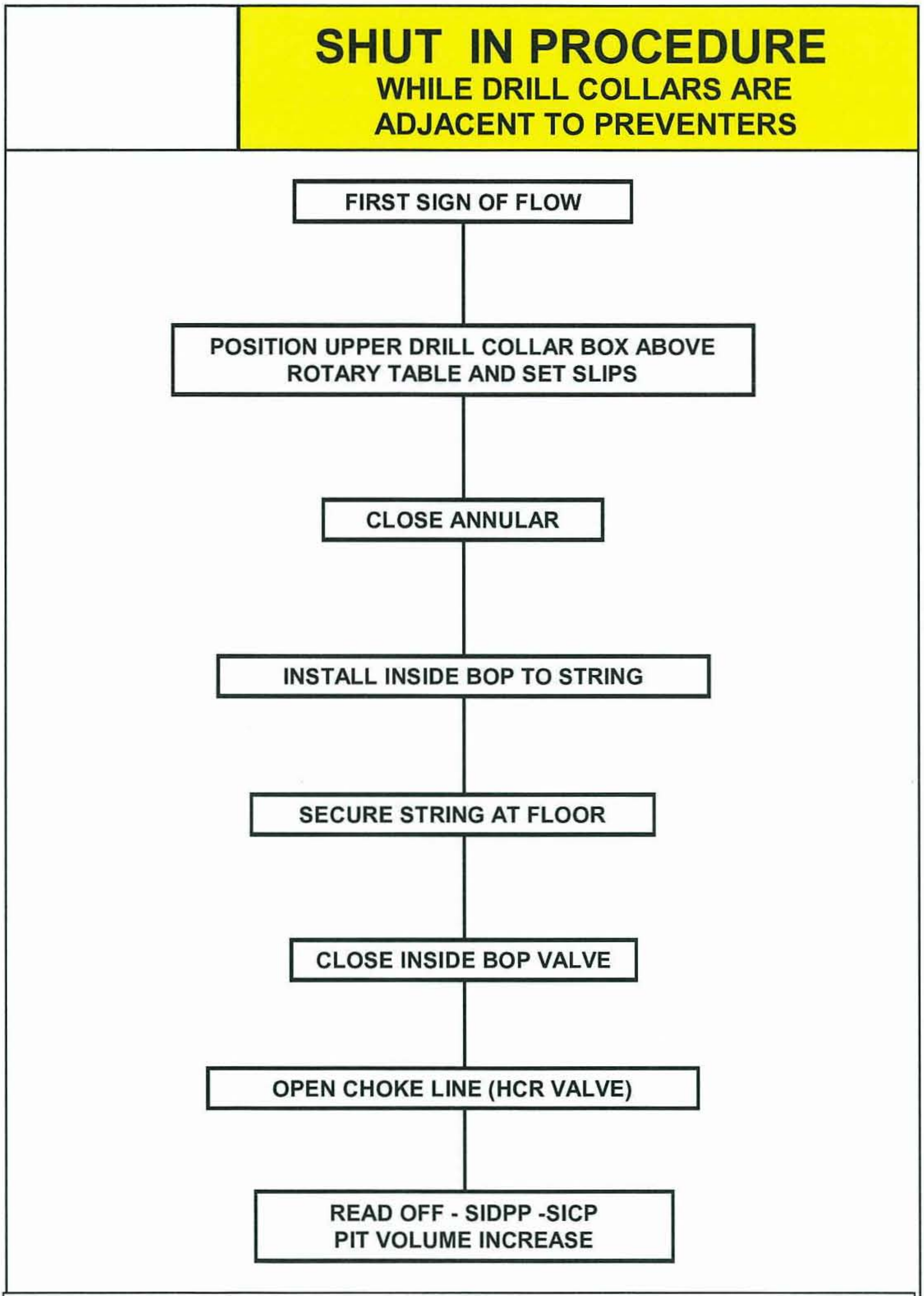


Figure 18. **Well Shut-in Procedure (Drill Collars Adjacent to Preventors)**

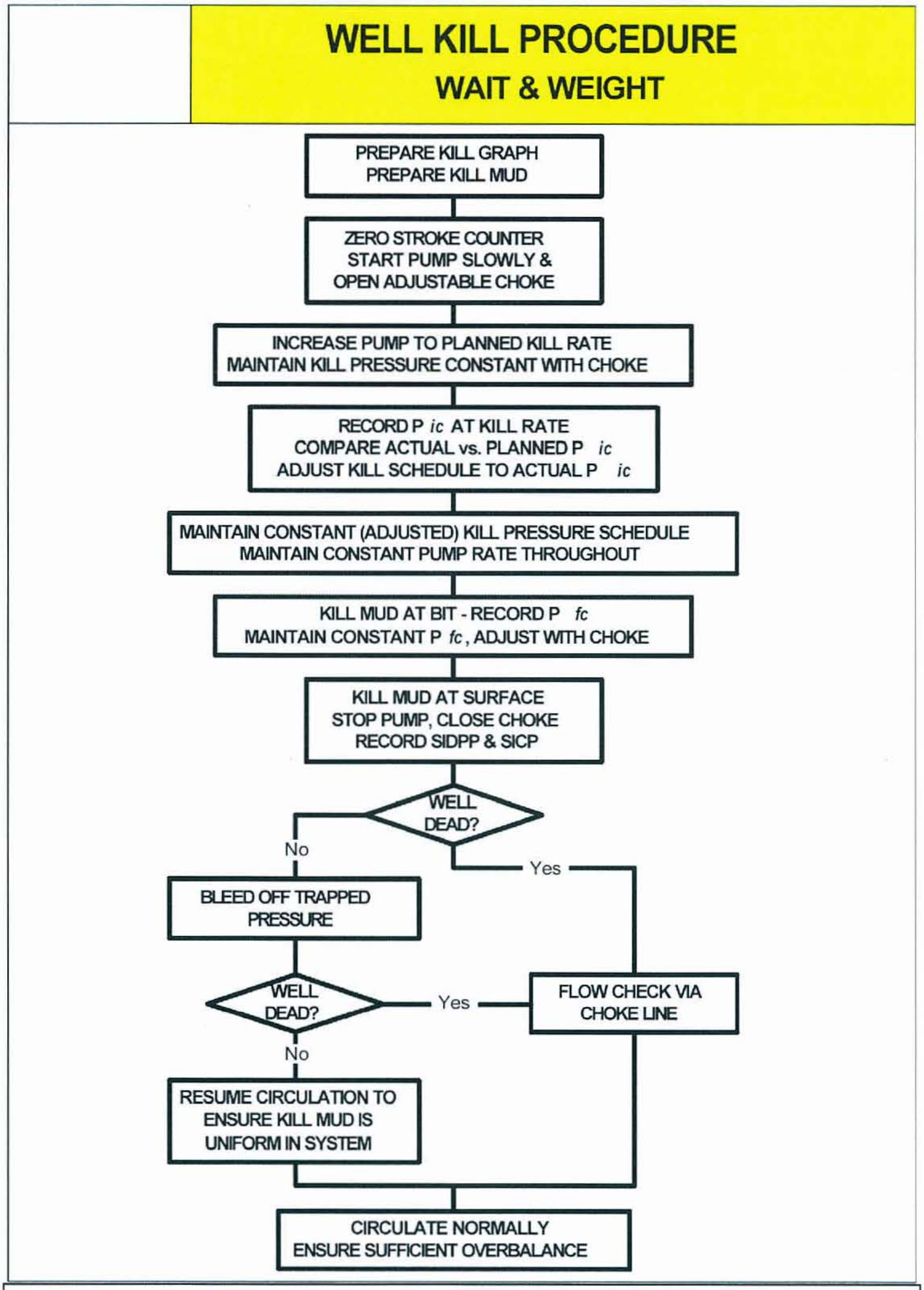


Figure 19. Well Kill Procedure - Wait and Weight Method

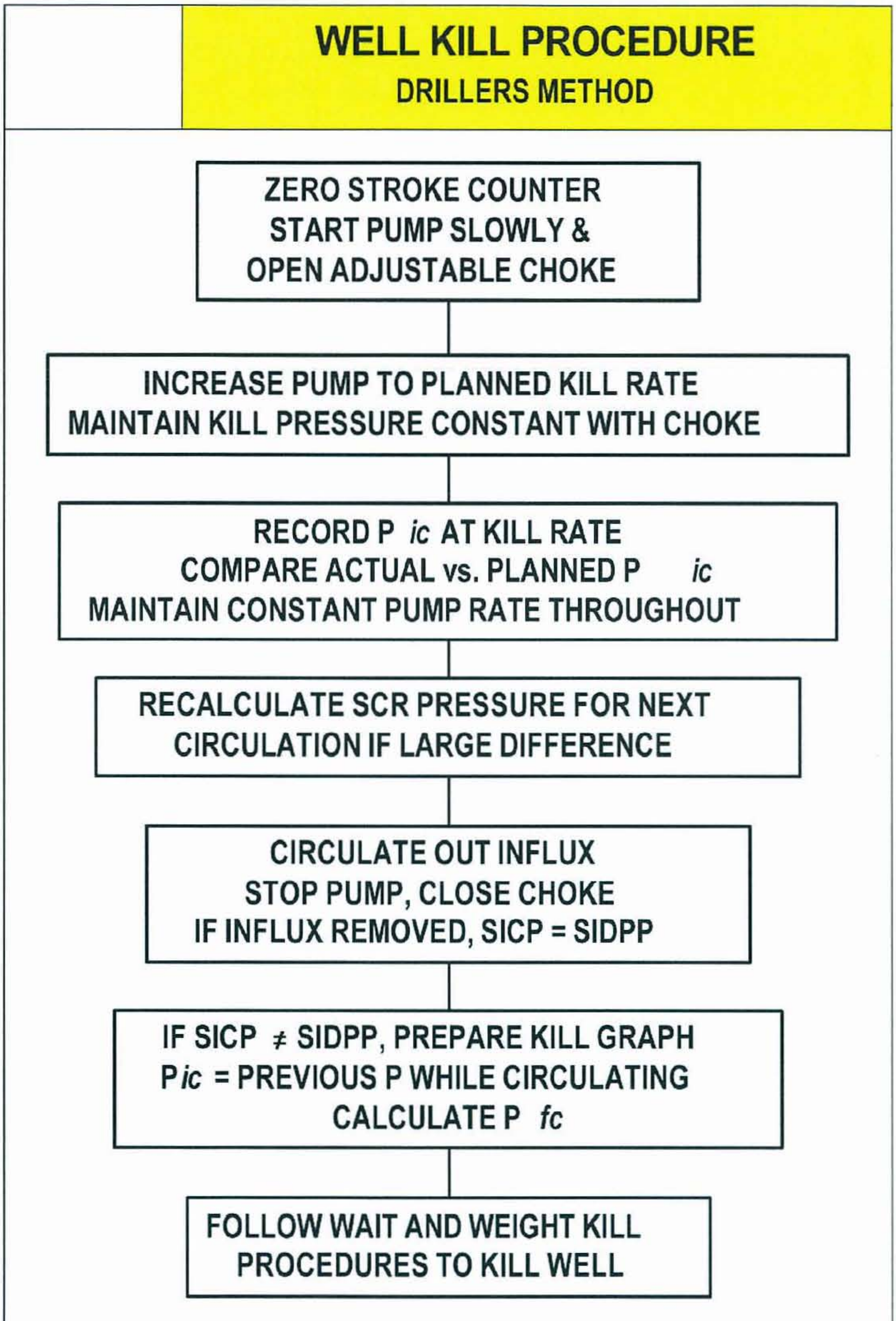


Figure 20. **Well Kill Procedure - Drillers Method**

WELL KILL PROCEDURE

VOLUMETRIC CONTROL METHOD

(DRILLPIPE PRESSURE)

REQUIRED: DRILLPIPE ON BOTTOM.
NO DRILL STRING FLOAT INSTALLED.

STEP 1

PREPARE KILL MUD.
DETERMINE MIGRATION RATE OF INFLUX.

STEP 2

ALLOW DRILLPIPE PRESSURE TO INCREASE BY PLANNED OPERATING & SAFETY MARGINS

STEP 3

BLEED OFF MUD FROM CHOKE UNTIL DRILLPIPE PRESSURE REDUCED BY OPERATING MARGIN
(NEW SIDPP = OLD SIDPP + SAFETY MARGIN)

STEP 4

VERY SLOW PROCESS.
SLOW CHOKE BLEED-OFF TO MATCH INFLUX MIGRATION RATE.
DELAYED DRILLPIPE PRESSURE RESPONSE DURING SLOW CHOKE BLEED-OFF.

STEP 5

ESSENTIAL THAT BOTTOMHOLE PRESSURE REMAINS ABOVE FORMATION PRESSURE

STEP 6

REPEAT STEPS 2, 3, 4 & 5 UNTIL INFLUX IS AT SURFACE.
DO NOT VENT OFF GAS.
LUBRICATE IN KILL MUD IF REQUIRED
(SEE CASING PRESSURE METHOD).

Well Control Procedure - Volumetric Control Method (Drill pipe pressure)

Santos

WELL KILL PROCEDURE
VOLUMETRIC CONTROL METHOD
(CASING PRESSURE)

STEP 1
PREPARE VOLUMETRIC WORKSHEET.
PREPARE KILL MUD.
DETERMINE MIGRATION RATE OF INFLUX.
CALCULATE HYDROSTATIC OF 1BBL MUD IN ANNULUS

STEP 2
ALLOW CASING PRESSURE TO INCREASE BY PLANNED OPERATING & SAFETY MARGINS.

STEP 3
BLEED OFF EQUIV. VOLUME MUD TO OPERATING MARGIN,
MAINTAIN CASING PRESSURE CONSTANT
(SLOW PROCESS, MATCHES MIGRATION RATE).
MAINTAIN SAFETY MARGIN.

STEP 4
REPEAT STEPS 2 & 3 UNTIL INFLUX IS AT SURFACE.
DO NOT VENT OFF GAS

STEP 5
PUMP KILL MUD TO PLANNED PRESSURE VIA KILL LINE.
ALLOW TIME FOR KILL MUD TO FALL THROUGH INFLUX.

STEP 6
BLEED OFF GAS, REDUCE CASING PRESSURE
BY EQUIVALENT KILL MUD HYDROSTATIC.
SHUT IN IF MUD RETURNS ARE OBSERVED.

STEP 7
REPEAT STEPS 5 & 6 UNTIL ALL GAS IS VENTED.

Figure 21. Well Kill Procedure – Volumetric Control Method (Casing Pressure)

WELL KILL PROCEDURE

BULLHEADING

DETERMINE MIGRATION RATE OF INFLUX.
PREPARE SUFFICIENT MUD TO DISPLACE
1.5 x HOLE VOL. FROM TOP INFLUX TO TD
(IF TIME, RAISE WEIGHT BY 0.3 - 0.5 ppg).

PREPARE MAASP FOR MUD IN HOLE.
LINE UP 1 PUMP ON ANNULUS.

PUMP SLOWLY DOWN ANNULUS, ESTABLISH INJECTION RATE.
<u>PUMP RATE MUST BE GREATER THAN MIGRATION</u> RATE.
MAINTAIN CONSTANT PUMP RATE,
PLOT INJECTION PRESSURE vs. VOLUME.

DO NOT EXCEED MAASP.
PRESSURE INCREASING - SHUT DOWN & OBSERVE.
PRESSURE DECREASING - BULLHEAD SUCCESSFUL.

IF PRESSURE DECREASES WHEN SHUT DOWN,
CONTINUE BULLHEAD AT MAXIMUM RATE.

CONTINUE PUMPING TO OVERDISPLACE
TOP INFLUX TO TD BY 50%.

SHUT DOWN AND OBSERVE WELL.
SICP SHOULD APPROX. EQUAL SIDPP

PREPARE KILL MUD IF NECESSARY.
CIRCULATE USING WAIT & WEIGHT PROCEDURE.

Figure 23. Well Kill Procedure - Bullheading

WELL KILL PROCEDURE

COMBINED STRIPPING & VOLUMETRIC METHOD

(ANNULAR ONLY)

PREPARE STRIPPING WORKSHEET.
PREPARE KILL MUD.
DETERMINE MIGRATION RATE OF INFLUX.
CALCULATE HYDROSTATIC OF 1BBL MUD IN ANNULUS

INSTALL INSIDE BOP; OPEN VALVE.
REDUCE ANNULAR CLOSING PRESSURE.
SLOWLY LOWER PIPE THROUGH ANNULAR;
ALLOW SLIGHT LEAKAGE.
REDUCE SPEED FOR TOOLJOINTS.

BLEED REQUIRED VOLUME MUD PER CONNECTION.
MAINTAIN CONSTANT BOTTOMHOLE PRESSURE
(CLOSED PIPE VOLUME, INFLUX MIGRATION,
ENTRY OF BHA INTO INFLUX ALL AFFECT BH PRESSURE).

CONTINUE STRIPPING DRILLPIPE TO REQUIRED DEPTH
TO KILL WELL.
UPDATE STRIPPING WORKSHEET EVERY STAND AND
BLEED-OFF OF MUD.
MAINTAIN OVERBALANCE AT ALL TIMES.
FILL DRILLPIPE WITH ORIGINAL MUD EVERY 5 STANDS.

Figure 24. Well Kill Procedure – Combined Stripping & Volumetric Method (Annular only)

Appendix III: Minimum Pressure Control Equipment Standards

General BOP Arrangement

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

Welded, flanged, or hub connections are mandatory on all pressure systems above 2000 psi (as opposed to threaded connections).

BOP stacks should comprise at least:

1. One annular preventer.
2. One double, or two single hydraulic operated ram type preventers; one of which must be equipped with correct size pipe rams, the other with blind rams. Locking mechanisms (integral or mechanical) are required for these preventers.
3. One full opening drilling spool with two 3" bore (min) side outlets.

A single 10 gallon surge bottle will be placed near the annular preventer on the close port of the hydraulic lines.

Choke And Kill System

The choke and kill system shall provide the valves and piping required to allow controlled circulation of the well under pressure. The assembly, connections, full opening gate valves, fittings, piping, etc., subject to well or pump pressure should be flanged, clamped or welded and have a rated working pressure at least equal to the rated working pressure of the BOP. The choke and kill system shall include:

A double valve arrangement on every line/outlet of the BOP.

A hydraulically operated (HCR) valve included in the double valve arrangement on the choke line.

Lines connecting the BOP stack to the choke manifold.

A choke manifold.

A flare line connected to the choke manifold.

Choke and Kill Lines

Dedicated kill lines must not be smaller than 2" nominal and shall be fitted with two gate valves and a non-return valve. Choke lines must not be smaller than 3" through bore and are to be connected with two valves to the BOP stack of which the outer valve shall be hydraulically operated (ie HCR).

Choke lines shall be as straight as practicable and firmly anchored to prevent excessive whip or vibration. Turns, if required, should be targeted. Excessive bends in piping or 'Co-Flexip' spec hoses is not acceptable. A 'Co-Flexip' spec hose is acceptable in "straight short runs only". The hose must be placed between the hydraulic controlled valve and the flow line leading to the choke manifold.

The distance between anchoring points shall be 4 m (12 ft) or less.

Threaded connections and hammer unions are unacceptable in any section of the line.

Choke Manifold

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

a) All components should be selected in accordance with applicable API Specifications, taking into consideration pressures, volumes, temperatures and conditions under which they may be operated (i.e. gas, oil, drilling fluid, hydrogen sulphide, the environment, etc.).

b) All choke lines shall be 3" nominal diameter or larger, have a minimum number of turns and be securely anchored.

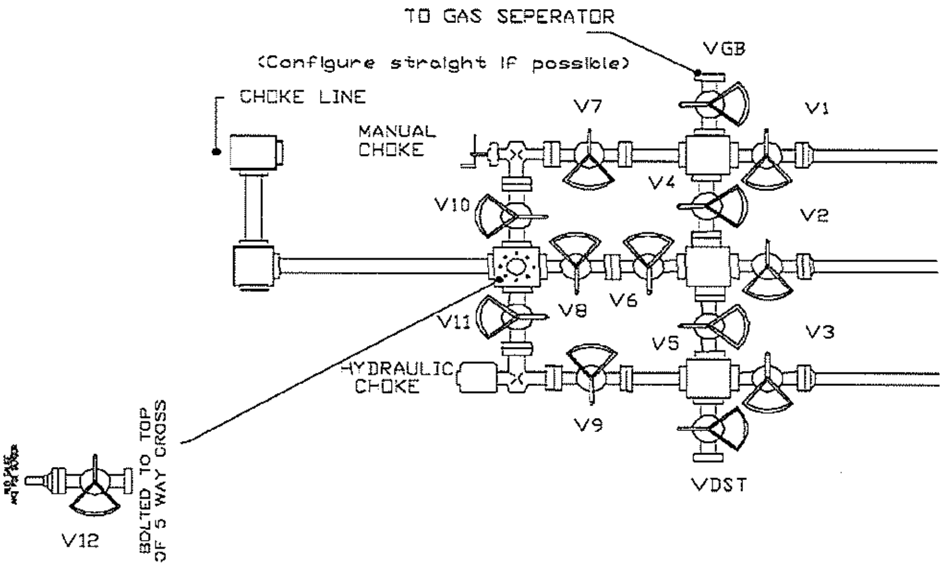


Figure 25. Minimum Choke Manifold Arrangement

c) Only right angle block turns shall be used in the choke manifold and discharge piping.

d) A 3" nominal internal diameter inlet (or larger) shall be provided into a block five way cross. The through bore of the cross will be 3" diameter (or larger) and the right angle flow paths shall be 3" diameter (or larger).

e) Outboard of the right angle flow path gate valves, will be one two inch, remotely operated hydraulic choke and one two inch, manually operated choke.

f) A pressure gauge and a remote sensor measuring the inlet pressure to the manifold shall be provided.

g) A remote choke control station shall be provided for the remotely operated choke,and must include all monitors necessary to furnish an overview of the well control situation. This includes standpipe pressure, casing pressure and pump strokes. Rig air systems must be of adequate capacity to provide the necessary pressure and volume requirements for control of hydraulically or pneumatically operated chokes and valves. A redundant automatic choke control system, which may be manually operated, should be provided in the event that rig air becomes unavailable

h) Baffle chambers not permitted – see Figure 25.

i) The flare line downstream of the choke manifold shall be 45 m (150") in length, with a minimum internal diameter of 2.7" (ie 3 ½" tubing).
In addition, chokes should incorporate a suitable bleeder valve facility to ensure that the pressure can be released prior to removal of the bonnet nut. Hammer type threaded bonnet nuts are not recommended. Flanged or bonnet clamp connections are preferred

Mud-Gas Separator

The unit vessel shall have a minimum inside diameter of 1.2 m (48") and be at least six metres (twenty feet) in length.

The top and bottom sections of the vessel shall be curved or dome topped. No flat top or bottom is acceptable. The vessel shall withstand a static pressure test of 600 psi when manufactured. Vessel will not be required to be pressure tested at regular intervals.

The mud gas separator shall be installed with a minimum 8" vent line, a minimum 4" choke manifold discharge line, and a mud seal of at least 1.5 m (5 ft) The mud gas separator discharge line (and the choke manifold discharge line) shall under no circumstances, be connected to the vacuum degasser inlet.

The following shall be met when configuring the pipework for the mud/gas separator;

- there are to be no valves, pipe expansion or contractions within 3 m (10 ft) of the inlet nozzle.
- if a bend is required in the feed pipe it shall be in a vertical plane through the axis of the feed nozzle.
- the gas outlet line reducer should be no nearer to the top of the vessel than 0.6 m (2 ft).

The mud-gas separator shall have the vent lines (8" min) leading to the flare pit (ie approx. 150' from well centre) and be manufactured from Schedule 40 (or higher) rated pipe. Low places in the vent lines should be avoided in order to prevent liquids being trapped in them.

The mud discharge line of the separator must be at least 6" in diameter and of similar pressure rating of the vessel.

A dump outlet shall be constructed at the base of the vessel and equipped with a full open valve consistent with the pressure rating of the vessel.

Vacuum Degasser
A vacuum degasser is required on all rigs. Degasser systems shall be positioned on the intermediate section of the active pits, the discharge may be allowed to flow into the suction pit. The flow capacity of this degasser must be at least equal to the maximum drilling flow rate expected in production hole (500 gallons per minute). A centrifugal type degasser is acceptable.

BOP Control Systems
Control systems for surface BOP stacks shall consist of the following:

- One independent automatic accumulator unit rated for 3000 psi WP with a control manifold, clearly showing 'open' and 'closed' positions for preventers and the hydraulic operated choke line valve. It is essential that the BOP operating unit be equipped with 0-3000 psi regulator valves similar to the Koomey type TR-5 which will not 'fail open', causing complete loss of operating pressure.

The system will be supported by two independent hydraulic power sources. These sources can be powered by rig air or electric powered pumps. These pumps will be rigged to automatically recharge the unit as the pressure in the accumulator bottles drops. Accumulator charging pump output shall be capable of charging the accumulator system from precharge pressure to operating pressure in 15 minutes or less.

The unit shall be located in a safe area away from the drilling floor. It shall include a low pressure warning alarm and hydraulic fluid level indicator or low fluid level warning alarm.

- All BOP stack installations should have at least one graphic remote control panel showing 'open' and 'closed' positions for each preventer and the pressure operated choke line valves. This panel must include a master shut-off valve and controls for regulator valves and for a bypass valve. The panel must be located near the driller's position. If the accumulator unit is not located in a safe area, a second remote panel must be available (in a safe area).

- High pressure fire-resistant control hoses with a working pressure of 3000 psi are preferred, although steel swivel joints are acceptable. The hoses should be steel wrapped (co-flex type) to provide greater resistance to fire and improved durability.

Accumulator Requirements
With an initial precharge of 1000 psi, the accumulator volume should be sized to keep at least 1200 psi on the unit (with pumps inoperative) after:

- Closing all functions
- Opening all functions
- Closing the annular
- Opening the remote operated valve

Closing systems of BOP's shall be capable of closing each ram preventer within 30 seconds; the closing time should not exceed 30 seconds for annular preventers smaller than 20".

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

The following drill string BOP valves (with connections and/or cross-overs to suit the drill pipe and collars in use) shall be available on the drill floor and ready for immediate use at all times:

- A full bore Kelly Cock shall be installed at the base of the kelly.

- A ball type stabbing valve (lower kellycock), together with an operating handle for the valve, and removable handles for easy stabbing.

- A rotating type circulating head

- Inside BOP (Gray type or equivalent).

The outside diameter of the tools will be similar to the tool joint outside diameters to facilitate stripping operations.

A test sub for testing the kelly and kelly cocks shall be available on the rig.

Kick Detection And Well Monitoring Equipment
An indicating and recording mud pit level system, capable of providing early visual and audible warning of gain or loss of fluid in the well, shall be installed in those mud tanks which serve as active mud tanks. This system must be able to detect and allow shut in response by the Driller for a maximum loss/gain of 5 barrels.

The complete system must be kept in proper working condition at all times. An indicator or recording chart must be easily visible to the driller.

Other minimum requirements are below:

a) The following minimum kick detection equipment shall be available and fully operational:

- Flowline monitor
- Trip tank complete with a mechanically operated indicator of the trip tank level visible from the Driller's position. This system must be able to detect and allow a shut in response by the Driller for a maximum loss/gain of 1 barrels

b) Continuous monitoring and recording of the following parameters:

- Weight on bit and hook load
- Standpipe pressure and choke pressure
- Rate of penetration
- Mud pump rate(SPM)

CHAPTER 11
SUSPENSION AND ABANDONMENT

TABLE OF CONTENTS

11.1 OBJECTIVES

The Drilling Department shall produce "fit for purpose" suspension or abandonment designs in accordance with the standards and procedures detailed in this chapter and relevant statutory requirements and regulatory standards. The suspension and/or abandonment section of the Drilling Program shall ensure that:

- The final well status meets all relevant statutory requirements regarding zonal isolation.
- Primary well control is in place and shall not deteriorate with time.
- Cement plugs are set and tested with a minimum of delay.

The DSV shall ensure that the requirements for the suspension or abandonment detailed in the program are carried out by the Drilling Contractor in accordance with the standards and procedures contained in the following sections.

11.2 RESPONSIBILITIES

Responsibilities for the implementation, supervision and verification of suspension, abandonment and lease clean-up operations are tabulated below.

Task	Performed by	Verified by
Prepare suspension / abandonment programme (part of Drilling Programme)	DM	DM
Submit Suspension or Abandonment programme to regulatory authority for approval	DM	DM
Identify formation tops.	Mud Loggers / WGL	DSV
Execute the Suspension or Abandonment Programme	Drilling Contractor	DSV
Verify integrity of the plugs as specified	Drilling Contractor	DSV
Prepare Reports (Form F-331 and Form F-332) with diagrams	DSV	DM
Execute initial lease clean-up	Drilling Contractor	DSV

Table 66. Responsibilities for Suspension, Abandonment and Lease Clean-up

11.3 STANDARDS AND GUIDELINES

The GSLM standards for the suspension or abandonment of wells are outlined in this Chapter.

All wells that are permanently suspended or abandoned must be left in a condition that prevents the potential leakage of formation fluid to surface.

11.3.1 Well Suspension

The following standards shall apply to the long term suspension of wells:

1. To protect against ingress of wellbore pressure into the production casing, the well shall have, as a minimum, two lines of defence present of which at least one has been tested. These may include:

    - The Casing string
    - Cement filled shoe track
    - Mechanical Plug
    - Kill weight fluid

    Kill weight mud/brine can only be considered a line of defence if its weight is known and it has been tested to above leak-off to ensure there are no losses. The settling of weighting elements shall also be considered.

2. Suspended wells which have open perforations shall have all perforations isolated by a bridge plug and a cement plug depending upon the well requirements.

11.3.2 Well Abandonment

General Standard

Each well is to be evaluated individually to design the abandonment program. Abandonment of wells or sections of wells shall be conducted in such a manner that reservoir management is not compromised, hydrocarbons are prevented from migrating to surface or between zones of differing pressure regimes, and the well location is restored to its original condition or to an agreed condition. All potable water bearing, saline water bearing or hydrocarbon bearing permeable zones shall be effectively isolated from one another.

Potable Water Supplies

It is a statutory requirement that any saline water sands shall be isolated from fresh water sands in order to prevent contamination of artesian potable water supplies.

Hydrocarbon Zones

It is a statutory requirement that isolation procedures shall prevent commingling of any hydrocarbon or water producing zones.

Isolation Of Open Hole

- The open hole shall be isolated by placing a series of cement plugs (each a minimum of 50 m) to extend 25 m below into another permeable section if present, and 25 m above the top of the permeable/hydrocarbon zones (Refer to 8.10.2 for plug setting procedures).
- Only the cement plug set across the casing shoe needs to be pressure tested (LO plus 100 psi).
- Excess cement shall be 10% over caliper or 20% on theoretical volume if no caliper is available.
- In the absence of permeable/hydrocarbon zones the open hole shall be isolated by placing a cement plug across the previous casing shoe to extend a minimum of 25 m below and 25 m above the casing shoe.
- When lost circulation is anticipated, a mechanical isolation device should be set prior to setting the cement plug.

Isolation Of Hole With Stuck Pipe

- Provided that no permeable / hydrocarbon zones with cross flow potential are exposed in the stuck pipe section, the fish shall be isolated by cement plug(s) placed on top of the fish.
- In the event permeable zones do exist, attempts shall be made to isolate the annulus between the fish and the hole.

Abandonment of Casing Stubs

Casing stubs shall be isolated by a cement plug designed to extend a minimum of 25 m below the stub to a point 25 m above the stub. Alternatively a bridge plug can be set 15 m into the stub. In either case plugs must be located (tagged) and weight tested as a minimum and 25 m of cement plug set on top of a bridge plug.

Surface Cement Plugs

A surface cement plug of at least 15 m shall be placed in the smallest diameter casing string exposed at surface.

11.4 WELL SUSPENSION

The following standards shall apply to the long term suspension of wells:

- The well shall have a minimum two lines of defence present, of which at least one shall have been tested. These barriers may include:

Casing	Annulus
Cement filled shoe track	Cement filled annulus
Mechanical Plug	Annulus seal
Hydrostatic Head of kill weight fluid	Hydrostatic Head of kill weight fluid
The Casing string	

  Kill weight mud / brine can be considered a barrier, provided that its weight is known and it has been tested to above leak-off to ensure that there are no losses. The settling of weighting materials in the fluid shall also be assessed in determining the effectiveness of the fluid as a barrier over an extended period.

- All open perforations in suspended wells shall be isolated by a bridge plug and a cement plug (except where completion's have been run).
- If production casing is run, the well shall be suspended by installing an appropriate tubing spool.
- The wellhead or tubing spool shall be sealed by the installation of a blind flange or X-mas tree.

11.4.2 Procedures

If a well is to be temporarily suspended, the outline procedure below shall be followed:

1. Cement casing with top of lead cement a minimum of 150 m above the top of the previous casing shoe and the top of the tail cement 65 m above the uppermost hydrocarbon reservoir.
2. Pressure test the casing (as per the program).
3. Install tubing spool and companion flange (DO NOT energise the X-bushing at this stage).
4. Grease and cap off ring groove.

11.4.3 Minimum Mechanical Barrier Summary

The following minimum mechanical barriers are required prior to nippling down the BOP.

Borehole Location	Barrier
Annulus	1. Casing pack-off (slip and seal assembly / Tubing hanger). 2. Cement 150 m above the previous casing shoe
Wellbore	1. Wellhead 2. Kill weight fluid, and/or 3. Shoe track cement

Table 67. Minimum Mechanical Barriers - Suspension

11.4.4 Reporting

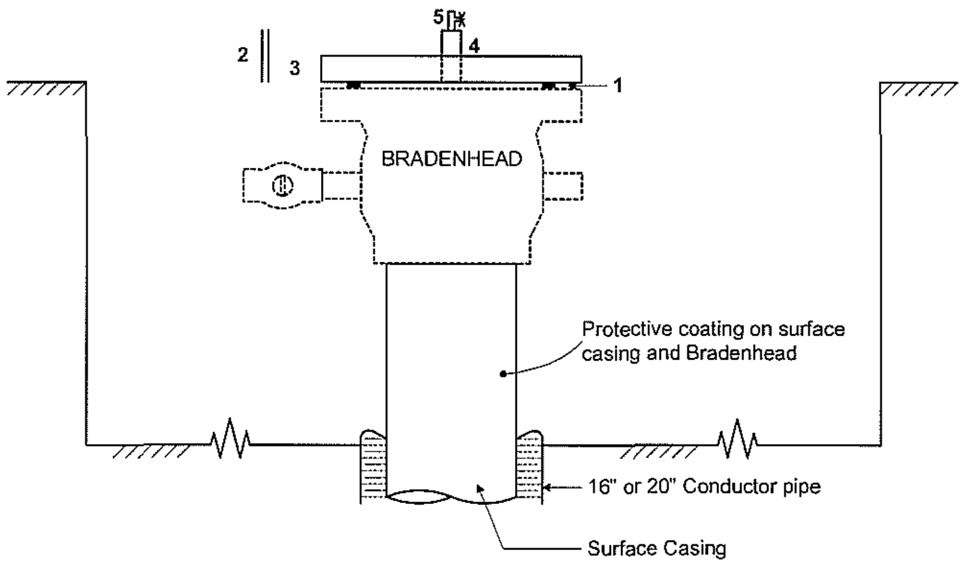
Upon completion of the suspension operations the DSV shall prepare the Wellhead Installation Report.

11.4.5 Suspension Schematics

The requirements for suspension and well status schematic diagrams are illustrated below for the following cases:

- Surface casing in place (2 string).
- Surface and intermediate casings in place (3 string).

WELL SUSPENSION
SURFACE CASING SET - (2 STRING)

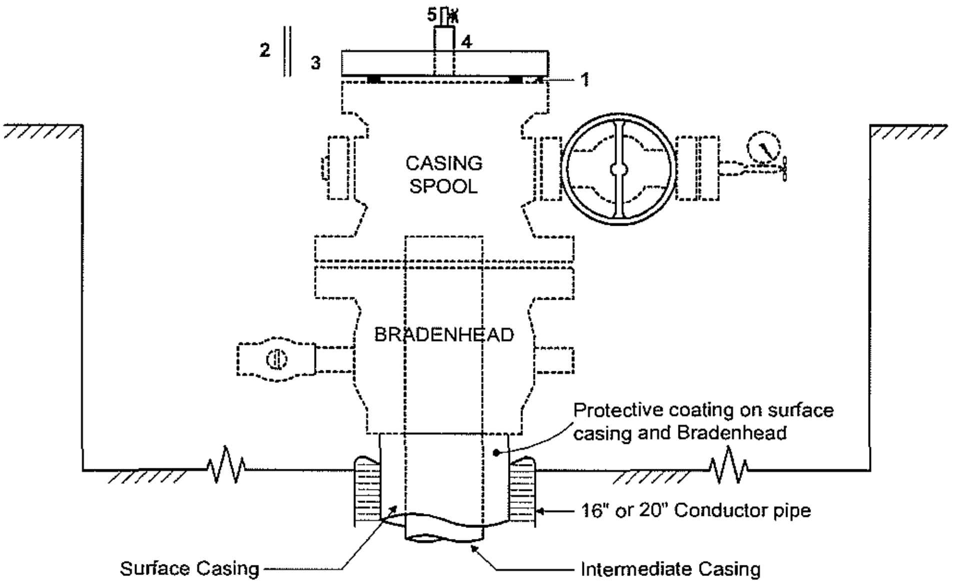


MATERIALS REQUIRED

ITEM NO.	QTY.	DESCRIPTION
1	1	RING GASKET
2	As required	STUDS C/W NUTS
3	1	FLANGE TAPPED 2" L.P.
4	1	BULL PLUG 2" L.P. TAPED TAPPED ½" N.P.T.
5	1	NEEDLE VALVE ½" N.P.T. MALE X FEMALE

Figure 26. Well Suspension Schematic - Surface Casing in Place

WELL SUSPENSION - SURFACE & INTERMEDIATE CASING SET (3 STRING)



MATERIALS REQUIRED

ITEM NO.	QTY.	DESCRIPTION
1	1	RING GASKET
2	As required	STUDS C/W NUTS
3	1	FLANGE TAPPED 2" L.P.
4	1	BULL PLUG 2" L.P. TAPED TAPPED ½" N.P.T.
5	1	NEEDLE VALVE ½" N.P.T. MALE X FEMALE

Figure 27. Well Suspension Schematic - Surface and Intermediate Casings in Place

11.5 WELL ABANDONMENT

11.5.1 Standards

The following standards shall apply to the abandonment of wells:

- Cement plugs should be set to isolate hydrocarbon zones, fresh water zones and zones containing saline water. Cement plugs should also be set across the previous casing shoe and at surface

  The open hole plugs shall extend 25 m below, into another permeable zone if present, and 25 m above the top of the permeable / hydrocarbon zones. Each plug should be a minimum of 50 m in length.
- Only the cement plug set across the previous casing shoe needs to be pressure tested (to LOT plus 100 psi.).
- Excess cement shall be 10% over caliper, or 20% on gauge hole if no caliper is available.
- In the absence of permeable zones the open hole shall be isolated by placing a cement plug across the previous casing shoe to extend a minimum of 23 m below and above the casing shoe. This plug should be pressure tested (LOT plus 100 psi).
- A surface cement plug of at least 15 m shall be placed in the smallest diameter casing string exposed at surface and between any casing strings not cemented to surface.

11.5.2 Procedures

When a well is to be permanently abandoned without running the production casing string, the outline procedure shall be as follows:

1. Set open hole cement plugs as required (see Chapter 8.10 of this Manual for plug setting procedures).
3. Set a 50 m cement plug across the previous casing shoe.
4. Pressure test casing shoe plug (LOT plus 100 psi).
5. Set surface cement plug 15 m (50') thick.
6. Nipple down the BOPs.
7. Remove casing spool and Bradenhead (see Spool Removal, below).
8. When the rig has been moved, install the Plug and Abandon Marker Plate. The Standard Marker Plate format is shown in Section 11.5.5.

11.5.3 Minimum Mechanical Barrier Summary

Borehole Location	Barrier
Wellbore	1. Surface cement plug 2. Casing shoe cement plug – must be pressure tested to LOT plus 100 psi. 3. Open hole plugs as required

Table 68. Minimum Mechanical Barriers - Abandonment

11.5.4 Removal of Wellhead Equipment

The following wellhead equipment shall be removed as applicable.

Removal of Spool

When removing the spool, wellhead equipment shall be handled assuming that it is suitable for refurbishment. The following shall occur:

1. The Spool and/or Bradenhead shall be removed (regardless of condition).
2. The Spool and/or Bradenhead shall be protectively packed and returned to the logistics base for a final decision on whether the item is to be refurbished or scrapped

Surface Casing in Place (2 hole section well)

On completion of the Abandonment Programme and removal of the BOP's, the Bradenhead shall be removed in one of the following ways:

- Back off the Bradenhead, if not welded.
- If welded cut the surface casing a minimum of 6 inches below the Bradenhead.

Surface and Intermediate Casings in Place (3 hole section well)

On completion of the Abandonment Programme and removal of the BOP's, the Spool and Bradenhead shall be removed in one of the following ways:

- Cut two diametrically opposed windows in the surface casing to allow cutting access to the intermediate casing. The windows should each extend for a maximum of 1/4 of the surface casing circumference, and the tops should be a minimum of 6" below the Bradenhead.
- Cut the intermediate casing, lift and remove the Spool.
- Remove the Bradenhead as above.

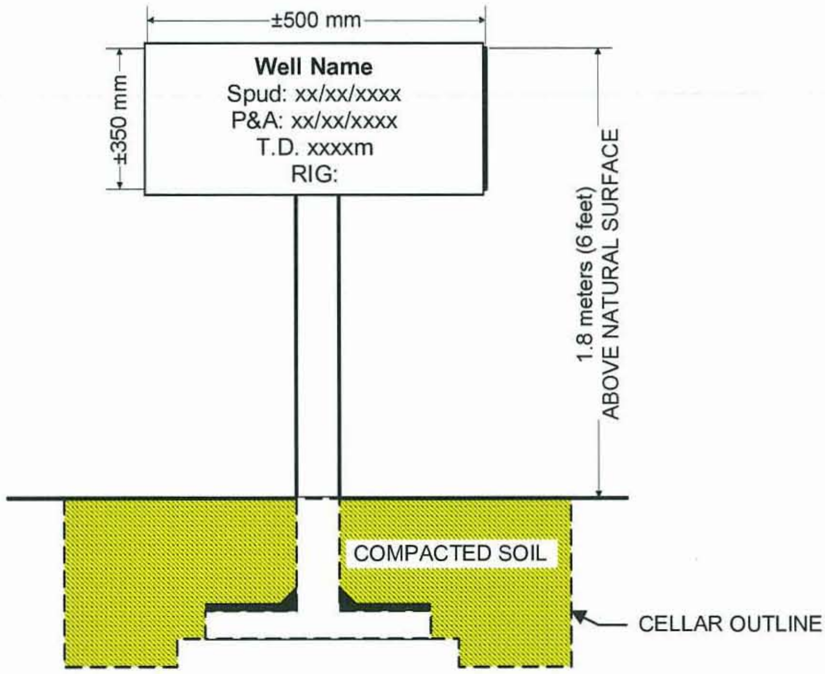
Reporting

Upon completion of the abandonment operations the DSV shall prepare the Well Abandonment Report.

11.5.5 Abandonment Schematic

A standard Plug and Abandon Marker Plate format is given in the figure below.

MARKER PLATE - P&A WELLS



1. Riser pipe to be minimum 2" O.D., welded to base plate fixed to 13-3/8" or 9-5/8" casing stub.
2. Top of I.D. plate to be 1.8 meters (6' 0") above natural surface (ie: after cellar filled in).
3. I.D. plate to be approx. 500 mm wide x 350 mm high (20" x 14") with well data bead welded as per above example.

Figure 28. Standard P & A Marker Plate Format

11.6 LEASE CLEANUP AND WASTE DISPOSAL

The following Sections provide a summary of the guidelines given in the lease preparation procedure.

11.6.1 Initial Lease Clean-Up

The DSV shall organise the following initial clean-up of the lease area at or near the time the rig is released. The following work is to be completed prior to the last personnel leaving the site.

- Any water remaining in the Turkeys Nest is to be pumped out so that the maximum amount of plastic pit liner can be recovered. The recovered liner is to be used on the next well location as protection between the shaker tank and the sump. If the water in the Turkeys Nest is required for completion operations the liner should be left in place. The DS will advise if this is required.
- Biodegradable rubbish should be placed in garbage bags, put in the correct segment of the rubbish bins and sent to the appropriate disposal depot.
- For plugged and abandoned wells, the rathole, mousehole and cellar must be filled to the level of the lease surface and compacted.
- For completed and suspended wells, the rathole and mousehole must be filled and compacted, the cellar ring removed and the cellar left unbackfilled.
- All recyclable materials are to be removed from the site and sent to the nearest Waste Management Depot for appropriate disposal.
- Any exposed or re-usable plastic which is lining the area by the shaker tank shall be removed and disposed of in the correct section of the rubbish bins. All other exposed plastic shall be cut off below the surface level in order to be covered once the sump is backfilled.
- A well identification plate (Marker Plate) shall be fabricated and securely installed where it is clearly visible (also see Section 11.5.5 above).
- The site must be cleared of all equipment and materials.
- An Initial Lease Clean-up Report shall be completed.

11.6.2 Final Lease Clean-Up

The drilling manager shall organise for the final clean-up to be conducted. This will include fencing the sump etc as part of the preliminary restoration. Final clean up will restore the lease to as close to original condition as practical.

CHAPTER 12
SPECIAL OPERATIONS

TABLE OF CONTENTS

12.1 OBJECTIVES

This Chapter provides an overview of the equipment and procedures used in non-standard drilling operational circumstances. These may be applicable to following personnel:

- Drilling Operations staff.
- Drilling Contractors.
- Specialist subcontractors.

The information contained in this Chapter can be used to improve the understanding of non-standard activities, and identify the alternative methods available.

12.2 RESPONSIBILITIES

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

Task	Performed by	Verified by
Stuck Pipe		
Address potential problems in the Drilling Programme	DM	DM
Conduct drilling operations to avoid stuck pipe	Drilling Contractor	DSV
Troubleshoot and free stuck pipe	DSV/ Drilling Contractor	DM
Run free point indicator logs	Logging Contractor	DSV
Back-off pipe	Logging/ Drilling Contractor	DSV
Decide to sidetrack	DSV/DM	DM
Stuck Logging Tools		
Ensure fishing equipment for all programmed logging tools available on site	DSV	DM
Notify Hobart office of stuck logging tools	DSV	DM
Decide on fishing method	Logging contractor/DSV	DM
Perform fishing operation	Drilling Contractor/ Logging Contractor	DSV
Milling		
Maintain list of milling equipment available at the wellsite / logistics base	DSV	DM
Notify Hobart office of milling requirements	DSV	DM
Decide to mill	DSV/DM	DM
Perform milling operations	Drilling Contractor	DSV
Fishing		
Maintain list of fishing equipment available at the wellsite/ logistics base	DSV/DM	DM
Notify Hobart office of stuck pipe or lost equipment in hole	DSV	DM
Decide to fish	DSV/DM	DM
Mobilise fishing specialist	DSV/DM	DM
Perform fishing operations	DSV / Drilling Contractor / Fishing Specialist	DM
Air Drilling		
Operate and maintain air drilling package	Air Drilling Contractor	DSV
Supervise drilling operations	DSV	DM

Table 69. Responsibilities for Special Operations

12.3 STUCK PIPE

Drilling is considerably influenced by a large range of lithological conditions. These conditions can cause the following potential drilling-related problems:

- Tight hole due to swelling / reactive clays.
- Cuttings pack-off around drill pipe.
- Differentially stuck drill string (depleted reservoirs)
- Washouts and hole erosion.
- Borehole breakout and hole ovality.
- Hard and abrasive drilling with a potential for key seating.
- Maintaining effective directional control.

The causes and remedies of stuck pipe are described in the remainder of this Section.

12.3.1 Stuck Pipe Risks and Controls

The stuck pipe risks and controls for different hole sections of wells drilled by GSLM are described below.

Surface Hole

Hole instability and potential losses are the primary concerns in surface hole. Guidelines to controlling these include. Another potential cause of stuck pipe is the presence of fractured or weathered Diorite which may cause blocks to jamb the drillstring.

- Maintaining an initial low mud weight (essential).
- Maintain good rheology with bentonite and native clays.
- Addition of LCM to minimise losses.
- Using KCl (normally 2-3%) to minimise hydration of clays
- Increasing mud weight at section TD if indicated by hole condition.
- Maintaining good dilution rates (generally >0.5 bbl/ft) to control solids build up.
- Drill Diorite with slick BHA's
- If possible use mineral rig to pre-drill diorite with air.

Intermediate/ Production Hole.

Very few wells have been drilled in Tasmania and consequently it is not possible to predict likely problems. It is therefore important to be prepared for hole problems of any type at any time.

A wide variety of sediments and drilling conditions can be expected while drilling these in Tasmania. These will range from less consolidated Tertiary sediments to the hard and consolidated Permian/Ordovician sediments. A Dioritic sill (often fractured), up to 500m thick, is present in most arrears of Tasmania and this has the potential to cause stuck pipe (blocks falling in) and lost circulation.

Guidelines for maintaining optimum hole and drilling conditions include:

- Maintaining a balance between tight hole and losses by control of mud properties, primarily weight.
- Observing careful tripping practices past permeable formations (Monitor Swab / Surge pressures).
- Perform frequent, short wiper trips as indicated by hole condition.
- Taking into consideration the time-dependent nature of drilling reactive clays.
- Keeping pipe moving as much as possible through and below depleted zones.
- Use BHA's appropriate to the interval being drilled.
- Closely monitor the drilling parameters and cuttings for indications of potential problems. i.e. Listen to what the well is saying.
- Don't take short cuts. Do things properly not quickly.

12.3.2 Causes of Stuck Pipe

Stuck pipe falls into the following categories:

- Differential sticking.
- Mechanical sticking.

Prevention of stuck pipe is detailed in General Drilling Practices (Chapter 3.5 of this Manual).

The Appendix at the end of this chapter provides charts for identifying the causes of stuck pipe.

Differential Sticking

In normal overbalanced drilling conditions, the pressure exerted by the mud column is greater than that of the formation fluids. If the formation is permeable, and the drill string lies against the wellbore wall, the pipe may become differentially stuck due to the build up of filtercake.

Mechanical Sticking

Mechanical sticking results from one or more of the following conditions:

- Inadequate hole cleaning (cuttings packing off).
- Formation instability (Diorite blocks falling in)
- Key seating.
- Under gauge hole and BHA changes.
- Drilling plastic formations.

12.3.3 Freeing Stuck Pipe

The first actions taken when the drill string becomes stuck greatly influence the chance of freeing the pipe. The following points give guidance on the correct early response. The Driller must be fully briefed on the actions to be taken when hole problems are expected.

Differentially Stuck Pipe

The force necessary to free differentially stuck pipe depends upon the following factors:

- The pressure differential between the wellbore and the formation fluid pressure.
- The area of the pipe surface which is embedded in the filter cake.
- The sticking force, which is directly proportional to the coefficient of friction between the pipe and the wall cake, may increase with time.

The correct early response to free differentially stuck pipe is:

1. Jarring shall commence by immediately pulling the pipe to the maximum safe pull specified for the assembly and drilling rig.
2. If pulling and jarring are not immediately successful, the pipe may be slumped and right-hand torque applied in an attempt to free the pipe.
3. The pipe should continue to be worked and circulation continued while preparing the pipe lax pill.

A pipe lax pill shall be spotted at the stuck point as soon as possible after initial attempts to mechanically free the pipe have failed.

Mechanically Stuck Pipe

The pipe should be immediately worked and jarred in the opposite direction to that when it became stuck i.e. if stuck when POOH, jar down, if stuck when drilling or RIH, jar up.

Notes:

- The maximum safe pulling limits for the pipe and rig should be determined prior to any jarring operations.
- Pipe should be pulled to the maximum safe limit for the assembly and rig (whichever is the least). If the first attempts to free the pipe are unsuccessful, the pipe should be worked in both directions until alternative action can be taken.
- Before using any lubricating pill, the effect on the hydrostatic pressure in relation to the pore and fracture pressures shall be taken into account.
- The overpull to trip the jars safely may not be as high as the maximum safe pull for the BHA.
- If circulation is not possible and the drill pipe is pressured in an attempt to initiate circulation, the pressure applied shall not exceed the Maximum Allowable Annular Surface Pressure (MAASP) without the prior approval of the DM.

Determine Effective Pull on Stuck Pipe

When determining the pull on stuck drill pipe, the actual weight of the string in air is to be used, and not the indicated weight, as recorded by the weight indicator. A worked example is given below:

DEPTH;	10.000'
Weight of drill collars in air = 743' of 6 ½" OD x 3" ID = 743 x 89	66,100 lb
Weight of DP in air = 9,257' x 20.77 lb/ft	192,200 lb
Total weight of string in air	**258,300 lb**
Indicator reading	205,000 lb
Weight of hook, blocks, swivel, etc.	27,000 lb
Pull reported at 100,000 lb over indicator reading	305,000 lb
Less hook, block, swivel, etc.	-27,000 lb
Effective pull on string	**278,000 lb**
Assuming that pipe is stuck on bottom, then the effective pull at the stuck point = 278,000 - 258,300 (no buoyancy of pipe)	**19,700 lb**
In order to apply a pull of 100,000 lb at the bit, the Indicator reading would have to be 258,300 + 27,000 + 100,000 lb.	**385,300 lb**
This would mean that the pull on the pipe amounts to 385,300 - 27,000	**358,300 lb**

Table 70. Worked Example for Determining Effective Pull on Stuck Pipe

Reducing Hydrostatic Pressure

Reducing hydrostatic pressure is the best way of freeing differentially stuck pipe.

However, it is essential that all aspects of well control be considered before lowering the hydrostatic head.

The preferred method of reducing hydrostatic pressure is to reduce the mud weight. However, pills to reduce the overbalance may be spotted. Close attention must be paid to all kick indicators.

Spotting Pipe Release Agents

Differentially stuck pipe can be freed by spotting pipe-free pills at the earliest possible opportunity. The volume of spotting fluid depends upon the annular volume at the stuck point, the length of section thought to be stuck and the ID of the BHA/DP

- Once the pill is in place, it must be left to soak whilst continuously working the pipe. Soaking times of at least 12 hours should be considered.
- During soaking, the pipe should be worked, preferably by putting it in compression. Slack off about 10,000 lb below the weight of the pipe and put in some right-hand torque. The amount of torque should be roughly half a turn for every 1000' of pipe above the suspected stuck point.
- Mix enough soak pill to cover the BHA plus additional volume of 5-8 bbls to move the soak pill approximately 1 bbl every 30 minutes.
- Consider mixing pill at twice the suppliers recommended concentration
- A bradenhead squeeze may be considered if initial attempts fail.

Jar Applications

There are two types of jars. These are described in the table below.

Jar Placement	Guidelines
Drilling Jars	• Normally run in the string and available as hydraulic or mechanical • In fishing operations, the jar is located directly above the fishing tool (i.e. overshot). Two to four drill collars should be placed above the jar. • Jarring performance will be reduced if there is a large difference between the drill collar/HWDP size above and below the jar. • Jarring performance will be reduced if there is a large difference between the drill collar/HWDP size above and below the jar. • Do not drill with the jars at their neutral point. A jar accelerator or "intensifier" may be run above the drill collars placed over the jar (between the drill collars and drill pipe) thus greatly increasing the effectiveness of the jarring action. Less drill collars may be run when an accelerator is used.
Surface Jars	• Used to jar downwards, for example to release key-seated pipe • The impact load can be adjusted, and jarring action is usually light to begin with, gradually increasing in intensity. • It is important not to pre-set the trip weight above the weight of the string that is free. Jars are located at surface below the kelly, or a stand can be placed above them.

Table 71. Guidelines for Jar Types

Jar Placement

In straight holes the jars shall normally be located two to four drill collars below the top of the BHA (never directly below the drill pipe or HWDP).

In deviated wells the jars may be placed lower in the BHA and run under compression.

Jars should never be run in neutral, as this will cause them to fail prematurely.

When determining jar placement, it is essential to ensure that the jars are run in tension and that there is sufficient buoyant weight of drill collars below them, plus 15% safety factor.

The following jarring practices shall be followed:

- Ensure that all surface pulling equipment is in good working condition.
- Ensure that both the weight indicator and deadline anchor are correct and clear of debris.
- Visually check the derrick for loose fittings.
- All personnel must be kept clear of the derrick and drill floor while jarring
- Pull shall be limited on stuck pipe to 85% of the minimum yield strength of the weakest member.
- When jarring, overpull to the maximum figure to trip the jar, wait for the jar to trip, then increase the overpull to that recommended for the pipe.
- Regularly inspect the derrick and drill floor for damage.

Note: Whilst circulating, pump-open forces greatly influence jarring performance and have to be carefully considered.

Free Point Determination

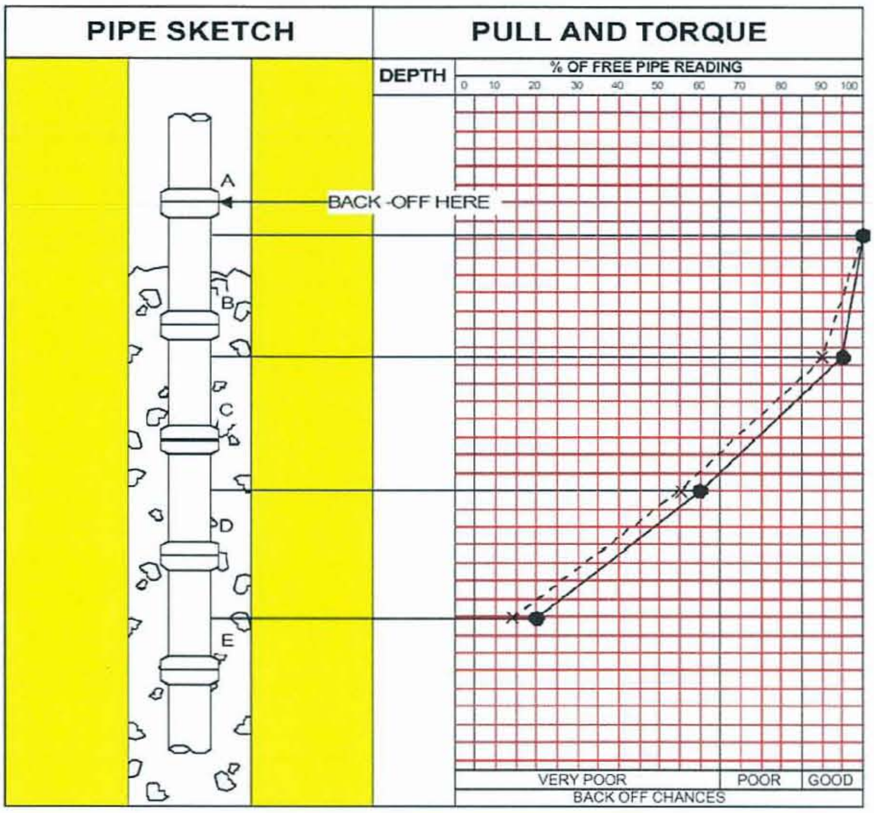
There are two methods to determine Free Point. These are tabulated below.

Method	Application
Stretch Method	Stuck point can be established by stretching the string and using the stretch charts for drill pipe. This method gives only an approximate value for the free point and should only be used to find the approximate stuck point for spotting pipe free pills and providing a starting point for using the Free Point Indicator Tool (FPIT).
Free Point Indicator Tool (FPIT)	This tool can be run on electrical wireline in order to back-off the string at the deepest possible point. By applying stretch and torque on the pipe, the FPIT can determine elongation or rotation at any depth. A plot of depth versus the percentage of surface torque and pull transmitted downhole shows the deepest point at which the string is free. This plot is shown overleaf.

Table 72. Free Point Determination Methods

FREE POINT DETERMINATION AND BACK-OFF PPROCEDURES

Differentially or stuck by heaving, sloughing formation.



To stretch or torque the pipe becomes more difficult as depth below the pipe free point increases. The FPIT decreases rapidly below collar B, the pipe should be backed-off either at collar A or collar B.

Figure 29. Diagram of Hole Condition and Typical FPIT Readings

12.3.4 Procedure for Backing-Off the Pipe

Before backing-off the pipe, the string shot size, weight, torque and turns on the string must be considered.

The string shot shall be determined by the Wireline Logging Contractor so that it is large enough to back-off the joint to be released without splitting the pipe. If the pipe does not back-off after the first shot, the charge can be increased on subsequent runs. The size of the primer cord bundle must be confirmed to be small enough to pass through the minimum pipe ID (this may be the jars).

Ideally the neutral point of the string weight distribution should be at the back-off point.The required surface pull to obtain a neutral point at the planned back-off point should be carefully determined when running the Free Point Indicator Tool.

Working Torque Down the Hole

Before working torque down the hole, the following safety precautions must be adhered to:

- Tong and slip dies must be clean and sharp and of the correct size.
- Tongs and back-up lines must be attached and in good condition.
- Slip handles should be tied together to prevent them jumping out of the rotary table in case the string parts high.
- Elevators should be latched around drill pipe but free from the tool joint, leaving the pipe free to rotate.
- The hook must be unlocked during rotation of the drill pipe.
- The possibility of residual torque when the drill pipe is first picked up must be considered. This may cause the slips to spin out of the rotary table.
- All non-essential personnel must be removed from the drill floor.

The procedure for working torque down the hole is as follows:

1. Set the string to the determined weight for back-off.
2. Mark the pipe at the top of the slips, and refer to that mark at all times (not the weight indicator as wall friction may give misleading effects on the weight reading).
3. Apply half of the left-hand torque required and lock the rotary table. Use a tong line and the rotary tongs to relieve the torque and unlock the rotary table, and hold the torque with the tongs.
4. Slowly pick up the string off the slips and work the pipe vertically several times, being careful not to go below the "weight" mark on the drill pipe, as the pipe could then part at some random point.
5. Set the pipe back in the slips at the weight mark and lock the rotary table at the applied torque.
6. If it is judged that the pipe will accept the remaining left hand torque, proceed to apply this. If not, apply half the remaining torque, in either case repeating the above procedure until all the required amount of left hand torque is in the drill pipe.

Note: Before applying left hand torque, torque the string to the right and note the torque-gauge reading. When later applying reverse torque, the torque reading should not exceed the maximum observed while torquing to the right.

Completing the Back-off

After the string shot has been detonated, check for back-off by picking up the string. In some cases the pipe may have only partially backed-off. To complete the back-off the following procedure must be followed:

1. Before applying left hand torque, torque the string to the right as before.
2. Apply approximately half the amount of left-hand torque originally used to back-off the string. While the torque is being applied, the pipe should back-off with a corresponding loss of torque load. If the pipe does not come free, release the torque in a controlled manner and note any loss of torque in the process
3. Repeat the process until back-off is completed.
4. After accomplishing the completed back-off, POOH.

12.4 STUCK LOGGING TOOLS

The wellsite geologist must be involved with all wireline logging tool fishing operations.

Logging tools may become stuck in either open or cased hole. The scenarios are described below

12.3.1 Open Hole

When a logging tool becomes stuck in open hole and all attempts to free it have failed, the following options exist (in order of consideration):

1. Strip over (cut and thread) the wireline cable to recover the tool.
2. Break the cable weak point and fish the tool.
3. Cement the tool in place.

The primary approach on all fishing operations (including tools with radioactive sources) should be to strip over the cable. This will minimise the risk of failing to fish the tool in an open hole configuration

Radioactive logging tools stuck in open hole shall always be fished by the stripover method. Under no circumstances shall the cable weak point be intentionally broken without the approval of the logging company and the DM. Reverse-strip out of hole.

For logging tools containing radioactive sources, the option of cementing in place may be subject to special regulations obtained through consultation with Mineral Resources Tasmania.

12.3.2 Cased Hole

For logging tools stuck in cased hole, the normal approach is to stripover the cable. As this will minimise the risk of the tool dropping free into open hole.

12.3.3 Stripping Over the Wireline Logging Cable

The following preparation shall be performed before stripping over the wireline logging cable.

Equipment

The following should be supplied by the Wireline Logging Contractor, and available on site for every logging tool to be run downhole.

- Fishing equipment (i.e. overshots) specific to the stuck tool.
- Additional tension meter with cable tension read-out for the Driller.
- 82 m of ¼" rope to control the run of cable going over the top sheave (if required).
- 27 m of ½" rope to hold the lower sheave straight (if required).
- Intercom between logging winch unit and drillfloor.
- Diagram of all tools with lengths, OD's, fish neck OD and length

Personnel

In addition to the regular drilling crew, the following personnel should be available throughout the stripping over operations:

- An experienced winch operator.
- One person at the rotary to engage and release the spear overshot.
- A Wireline Logging Operator on the drill floor to monitor the operation.

Preparation

An indicative sequence of events during the stripping over of wireline logging cable is tabulated below. The actual sequence will be determined by the Logging Contractors procedures.

Task	Preparation
1. Prepare Overshot	• Inspect, lubricate and dress the overshot contained in the loggers fishing kit. • Check the top end to ensure that the 2 3/16" bushing is in place. This holds the 2 ¼" hexagonal adapter of the lower rope socket, if the cable Is dropped at the surface.
2. Prepare Cable for Cut	• Secure the cable clamp (T-bar) to the cable, just above the rotary table. • Lower the cable until the cable clamp is supported by the rotary table. • Continue slacking off the cable, then cut it at a point 4 - 6' from the cable clamp, and secure the ends.
3. Re-rig the Derrick	• Position the lower sheave so that it does not interfere with drill floor operations, and hang the upper sheave from one of the main derrick beams, well above the drill pipe stand, in such a position that it does not interfere with the travelling block.
4. Prepare Cut and Thread Assembly·	• Fit rope sockets to both ends of the logging cable (standard types preferred). • Make up the remainder of the assembly, i.e. spearhead, spearhead overshot, swivel, and sub. Sinker bars may be added to the catcher assembly to provide the necessary weight.
Perform Full Test	• Latch the spearhead overshot to the spearhead while the cable clamp remains on the cable. Mark the cable adjacent to each rope socket with tape and test the cable with 2.5 MT tension for one minute. The end of the cable should be passed through the (fishing) overshot before the hex-adapter is replaced.

Table 73. Preparation of Stripping Over Wireline Logging Cable

Running in the Hole

The procedure for running in the hole while stripping over the logging cable is:

1. Pick up the first stand of drill pipe and install cross-over subs as required.
    - A circulating sub should be installed in all fishing strings
2. Draw the spearhead overshot up to the derrick man, who can then thread it through the first stand of drill pipe. If the sinker bars make the assembly too stiff to pass the travelling block, the assembly should be fed into each stand before it is picked up.
3. Attach the spearhead overshot to the spearhead and make-up the fishing overshot with chain tongs onto the bottom of the first stand.
4. With tension in the cable, check the operation of the remote tension indicator, then remove the cable clamp.
5. Complete the make up of the fishing assembly with the rig tongs.

6. Run the first stand into the hole:
   - Maintain a depth tally.
   - Maintain the cable tension to Wireline Logging Contractor specifications, paying close attention to the tension indicator.
7. Install the "C" plate and slack-off the cable until the slot in the spearhead is supported by the "C" plate.
8. The cable is now flagged for reference at each stand of drill pipe.
9. Release the spearhead overshot. Thread it through the next stand, and re-connect it to the spearhead.
10. Pull tension in the cable and remove the "C" plate. Make up the second stand onto the first and repeat the whole process for each stand.
11. Run in slowly and carefully, (according to the points listed in item 6), thus avoiding the following primary hazards:
    - The cable being dropped.
    - Broken armour wire balling-up ahead of the overshot.
    - The impact of the overshot on a bridge cutting the cable.
    - If the cable becomes key-seated it may double-back round the overshot.

    Note: Do not rotate the pipe in the hole.
12. When approaching the depth of the fish, it is good practice to clean out the fishing tool by circulating. Circulation at a bridge, at the fish, or during engagement of the fish is accomplished by hanging the cable spearhead on a bushing in a special circulating sub.
    - With the spearhead hanging on the "C" plate, thread the circulating sub and adapter sub over the spearhead overshot. Latch the spearhead overshot onto the spearhead, lift the cable and remove the "C" plate.
    - Make-up the subs onto the drill pipe. Place the special bushing over the cable and into the circulating sub. Lower the cable until the rope socket rests on the bushing. Unlatch the spearhead overshot.
    - Make up the kelly onto the circulating sub, using the appropriate cross-overs.
    - When the overshot is a short distance from the fish, the fish may come free. If this occurs circulation may be used to clean the overshot and then the logging tool can then be pulled into the grapple. The fish may, however, be covered by formation solids, requiring the overshot to be circulated down onto the fishing neck. In this case the overshot must reach the fish with sufficient tension still in the logging cable to prevent it going slack and looping over the rope socket.

Engaging the Tool

The fish can be engaged when the original tension at surface, including the weight of the logging tool, is known and the elongation (stretch) per 10,000' of standard logging cable sizes with respect to tool weight, has been determined from charts supplied by the Logging Contractor. The fish shall be engaged as follows:

1. Pull on the logging cable with the original logging tension and check the elevation of the spear point.

2. From the Logging Contractor's chart, find the cable stretch due to the weight of the logging tool in mud.

3. The elevation minus the stretch gives the elevation of the spear point for neutral tension in the cable at the logging tool. Space out the string with pup joints so that the spear point is below this elevation when the overshot engages the fish.
4. If circulating over the fish, continue pumping while lowering the pipe and engaging the fish. An increase in both pump pressure and cable tension should be noted as the tool head enters the overshot.
5. Stop circulating.

Pulling the Tool

After proving, by motion of the pipe and its effect on the cable tension, that the fish is engaged, the cable weak-point may be broken by:

1. Installing the cable clamp.
2. Latching the elevators around the cable, (under the cable clamp).
3. Pulling slowly until the weak point breaks.

The following procedure shall be adhered to:

1. Cut the cable to remove the rope sockets, then tie the two ends together with a reef knot. Tape the loose ends onto the logging cable to prevent them hanging up as they pass over the sheaves.
2. Spool the cable onto the winch, then pull the fish out of the hole.
3. Do not rotate because the fish may disengage from the overshot.

Problems while Stripping over the Cable

The following problems listed in the text and table below may be encountered whilst stripping over the wireline logging cable:

- If the spearhead rope socket fails, then a broken cable is left in the hole.
- If the spearhead with rope socket and cable is accidentally dropped into the pipe, run the thread through the overshot with the largest applicable guide down the pipe and attempt to engage the spear. If this fails, the drill pipe can be pulled because the bushing in the fishing overshot will catch the hexagon adapter on the spearhead.
- If a bridge is encountered, it should be removed by circulating gently.

The table below highlights some of the causes of changes to the cable which may occur when stripping over the cable.

Cable Tension	Cause
Increases Sharply	• The cable may be stuck in a key-seat and doubled back outside the overshot. • Picking up the pipe should cause a small decrease in tension. Increase the cable tension and the guide should free the cable ahead of the advancing overshot.
Increases Moderately Fast	• A broken armour cable may be balling up at the overshot.
Increases Gradually	• This is normal for a deviated well. The elevation of the spear point will be lower. • If the spear point becomes lower than the top of the pipe during running in, a short length of spacer bar may be introduced between the rope socket and spearhead.

Table 74. Increase in Cable Tension – Problems Whilst Stripping

12.5 MILLING

For the purposes of this Chapter, milling is defined as any non-planned milling of junk in open hole and in casing.

12.5.1 General Milling Guidelines

To effectively remove the cuttings while milling, the following should be adhered to:

- A minimum annular velocity to keep flow turbulent around the BHA should be used to prevent cuttings "bird nesting" and blocking the annulus.
- The Yield Point of the mud should be increased as high as possible before commencing milling.
- Viscous pills should be pumped if required.

Washing should begin at least one single above the fish. The fish should be tagged, the string picked up and rotation/washing started a minimum of one foot above the fish as the string is lowered. Weight and RPM should be adjusted to find the best milling rate while noting the rotating torque.

The table below tabulates some of the considerations to be made during milling operations.

Topic	Milling Considerations
Rotation	• Milling should be conducted using high rpm according to milling equipment manufacturer's instructions.
Weight	• A constant milling weight should be maintained. • The tool must not be allowed to drill off.
Monitor and Record	While milling, the following parameters must be monitored and recorded: · Progress made • Weight on mill • Torque • RPM • Pump pressure • Circulation rate • Description of milled cuttings • Any relevant observation

Table 75. Considerations During Milling

- In order to provide a high circulation rate, all subs and auxiliary tools should be full bore where possible. The tool must be picked up, circulated and rotated at regular intervals.
- BOP cavities must be flushed on completion of milling.
- The running of jars in the milling string should be considered on a case-specific basis.
- Stabilisers should be run to centralise the mill, but the number of stabilisers must be kept to a minimum to prevent excessive torque and bird nesting of cuttings.
- Ditch magnets should be used at the shale shakers or flowline. These magnets must be cleaned regularly and the weight of steel recorded.
- When milling junk, spudding should be periodically carried out to pound junk down to the bottom of the hole where it can be effectively milled.

The following table contains a summary of general operating recommendations and normal milling rates.

Type	RPM	Weight (1000 lb)	Remarks
Junk Mill	100+	10 - 50	Spud mill from time to time
Pilot Mill	125+	6 - 20	Vary weight to find best ROP
Taper Mill	50 - 80	6 - 30	Start with light weight & low rpm
Economill (Flat Mill)	100+	2 - 40	Start mill above fish
Rotary Mill	50 - 100	5 - 20	Pick up from time to time. Check overpull and torque

Table 76. General Operating Recommendations For Milling Operations

Material	Junk Mill	Pilot Mill	Flat Mill	Rotary Shoe/ Washover Shoe
Drill pipe	2.0 - 6.0	2.0 - 6.0	-	6.0 - 20.0
Drill Collars	1.0 - 2.0	1.0 - 2.0	-	4.0 - 6.0
Packers	4.0	-	2.0 - 3.0	2.0 - 4.0
Bit Cones, etc.	2.0- 4.0	-	-	-
General Junk	3.0 - 5.0	-	2.0 - 4.0	-
Washover Pipe	2.0 - 4.0	4.0 - 6.0	-	-

Table 77. Expected Milling Rates (ft / hr.)

12.5.2 Guidelines on Milling Junk

Guidelines for milling junk are tabulated below.

Milling Junk	Guidelines
In Open Hole	• The mill should be only 1/8" to ¼" less than the open hole diameter. • A junk sub should be placed in the milling assembly.
Inside Casing	• A non-rotating stabiliser may be run above the mill with the same OD as the mill head, which should be approximately the same as the drift ID of the casing. • At least one junk sub should be placed in the milling assembly. • No cutting action on sides of mill (to avoid damage to casing).
With a Pilot Mill	• A mill of similar diameter to the fish diameter should be used but stabiliser blades should be larger than the OD of the fish to be milled if hole conditions allow.
With a Taper Mill	• The diameter of the taper mill should be equal to the enlargement required. • Rotate slowly while entering the fish. • After the restriction has been enlarged, the rotation can be increased to 80-100 rpm while reciprocating the mill through the interval several times **Note:** The weight on the mill should be kept as low as possible. Beware of torque-up exceeding 80% of drill collar make-up torque.

Table 787. General Guidelines to Milling Junk

12.6 FISHING

This Section describes practices, tools and procedures used by GSLM during fishing jobs.

12.6.1 General Fishing Guidelines

In the event that equipment becomes lost or is stuck in the hole, the drilling should be notified immediately by the DSV. The decision to mobilise fishing specialists shall be made by the DM.

In principle, the preferred method of fishing shall be the overshot method. However, each case will be evaluated individually.

The following considerations (and questions) should be considered in deciding the optimum course of action:

- The type of equipment in the hole to be fished (drill pipe, collars, junk, bit cones, etc.).
- The fishing profile presented.
- The condition of the hole/mud. Will formation instability cause the hole to deteriorate?
- Is the fish stuck? If yes, what is causing it to be stuck?
- What is the probability of freeing the fish?
- Can tools be run inside the fish or should they be run outside it?
- Will wireline tools have to be run through the fishing assembly?
- What are the anticipated times and costs to free the fish?
- What is the optimum economic fishing time? (Economics shall be performed by the DE).
- Are there open reservoirs below the fish? Does this have any implications for well control?
- Is it necessary to run a pump out (or circulating sub) above the overshot in order that the well can be circulated in the event of a pack-off after engaging the fish?.

Classification of Fishing Tools

The table below shows a general classification of types of fishing tools and their applications.

Type of Fishing Job	Type of Fishing Tool	Names of Tools
Recovery of Tubular Fish	Connecting Tools • External catch • Internal catch • Accessories	• Overshot • Die collar • Taper tap (poor class of tool: overshot always preferable if available) • Spear (provides very good connection) • Bent drill pipe single • Hydraulic knucklejoint • Hydraulic wall hook • Wall hook
	Washover Tools	• Washover safety joint • Washover pipe • Washover shoe
	Force Multiplier Tools	• Jar, hydraulic or mechanical • Bumper sub • Surface bumper jar • Accelerator • Hydraulic pulling tool
Recovery of Fish	Disengagement Tools	• Safety joint • Bumper safety joint • External tubing/drill pipe cutter • Internal tubing/drill pipe cutter • Flash cutter (Schlumberger, etc.) • Jet cutter (Halliburton, etc.) • Chemical cutter (Schlumberger, etc.) • Electrical cable back-off (Schlumberger etc.)
Recovery of Non-tubular Fish	Information Tools	• Impression block • Free Point Indicator • Junk basket • Circulating junk basket (+ coring) • Reverse-circulate globe-type basket • Magnet • Wireline spear • Junk sub • Milling shoe • Packer retriever • Section mill • Jet bottomhole cleaner

Table 79. Classification of Fishing Tools.

The fishing equipment carried by the drilling rig shall be specified in the Drilling Contract.

Fishing Equipment

The following fishing equipment should be available at the well site or from a third party supplier:

- Overshots and oversized guides complete with baskets grapples and mill control to catch all sizes of tools in hole.
- Fishing bumper sub (18" stroke) matching with drill collar string in use.
- Hydraulic jar with matching accelerator for the drill collar string in use.
- Surface jar with matching drill pipe connections.
- Reverse circulating junk basket.
- Junk sub with the same or larger OD as the drill collar strings.
- Lead impression blocks for the various hole sizes.
- Flat mills for all hole sizes.
- Pump out sub or circulating sub.

12.6.2 General Practices

The table below defines some of the preparation to be performed before a fishing job.

Task	Preparations Before Fishing
Timing	• The maximum economical fishing time shall be determined by the DM
Recording	• All fishing tool details must be recorded on a drawing before running the tool. The safe working load for all fishing tools and associated equipment must be determined.
Equipment	• If the fishing operation involves jarring, refer to Chapter 4.5 of this Manual and remainder of this Chapter. • Internal diameters of fishing tools to be run must be checked to verify that back-off tools can pass through them. • A bumper sub should be considered for use in all fishing assemblies.

Table 80. Considerations to be Made Before Fishing

The following guidelines shall be adhered to when fishing:

- Where a twist-off has occurred, the fish should be tagged before pulling out of the hole and the pipe should be strapped on the trip out.
- If a twist-off occurs while drilling and hole conditions permit the hole should be circulated clean and mud conditioned before pulling out of the hole.
- Determine the size, shape, and condition of the fish. Ensure that a detailed drawing is sent to the DM.
- The pull must be limited to 80% of the minimum yield strength of the weakest point.
- Before connecting to the fish, the following information must be obtained:
    - Establish circulating pressures and rates.
    - String weight up/down and rotating (with and without circulation).
    - Free rotating torque of string.
    - Pipe stretch and stroke of bumper sub, jars, etc.

12.6.3 Force Multiplying Tools

The purpose of force multiplying tools is to generate controlled blows onto a stuck fish. These blows can be in an upward direction, a downward direction, or selectively applied in either direction.

Force multiplying fishing tools are divided into three groups as described in the table below:

Tool	Guidelines
Jars	• Mechanical or Hydraulic (see Stuck Pipe section of this Chapter)
Jar Accelerators (Intensifiers)	• A gas charged (N2) accelerator or "intensifier" may be run above the drill collars placed over the jar (between the drill collars and drill pipe), greatly increasing the effectiveness of the jarring action. These are also available in double-acting mode, to match the jar action. Typical accelerator strokes are 6 - 15" depending on the tool used. • When used, less drill collars may be run without reducing the jarring impact force. • Jarring can be conducted at shallower depths where less string stretch and overpull is available, preventing the jar from achieving a full blow. • Use of an accelerator, by maximising the impact of the jar and reducing the shock load effect on the string, can significantly enhance the jarring impact force.
Bumper Subs	• Often used in conjunction with jars. • Provide a means of delivering upward or downward blows. • The sub should be installed immediately above the fishing tool or safety joint. Its presence assists operators to release the fishing tool in the event that the fish cannot be freed. • Delivers a sharp downward blow as well as transmitting torque required to break the fishing tool engagement and release it from the fish.

Table 81. Force Multiplying Fishing Tools

These tools are most effective when used by an experienced operator who can prevent severe damage to surface equipment and/or the string.

Procedure to "Bump Down" in the Hole

1. Pick up the string enough to open the tool completely and take a strain or stretch in the string. This shall be the length of the stroke plus the permissible stretch in the fishing string.
2. Drop the string to within 6" of the closed position of the tool and stop the string abruptly.
3. If sufficient stretch has been taken in the string, the lower end of the fishing string should bump downward closing the bumper sub and, due to the elasticity of the string, deliver a series of downward blows to the tool below the sub.

Procedure to "Bump Upwards" in the Hole

1. Pick up the string enough to open the bumper sub completely plus a moderate strain or stretch in the string.
2. Drop the string a distance equal to the stretch taken only and stop the string abruptly. This should cause the lower end of it to spring downward closing the bumper sub slightly. The string should rebound causing the bumper sub to open quickly and deliver a solid upward blow.

12.6.4 Overshot Tools

The following general considerations shall be made when planning the use of overshot tools:

- Grapple sizing should be taken from the manufacturer's specification. However, grapple sealing ID should not be more than 1/16" less than the fish OD.
- A pack-off should always be installed in order to circulate through the fish before pulling out of the hole.
- If the hole size is appreciably larger than the overshot OD, an oversized guide may be considered.
- If the pipe is lying in a recess or against the side of the hole, a hook wall guide or bent joint may be considered.
- If the fish cannot be engaged, an extension sub and a milling guide may be considered. A milling guide should always be run with a basket grapple.
- A basket grapple with long catch stop may be considered to catch an upset or box section of a tool joint.

Guidelines Before Engaging Fish

With the overshot directly above the fish, a combination of rotating and lowering shall result in the following:

- The guide directs the fish into the overshot.
- The fish can easily pass through the grapple because of its helical shape and mode of rotation.
- Too much rotation can damage/wear the grapple.

When lowering the overshot over the fish and once a pressure increase is noted, circulation must be stopped in order to prevent damaging the seal/packer. Bleed off any pressure trapped before engaging the fish.

The penetration of the fish into the overshot grapple must be limited in order to facilitate release from the fish. If the basket grapple used is not a long catch stop type, a stop must be used to prevent the grapple going completely over the upset of the fish. Not doing this makes it almost impossible to release the overshot from the fish.

Guidelines Before Releasing Fish

Unless an upward strain is maintained, the fishing string must never be rotated to the right while an overshot is engaged on the fish, other than when attempting to come off the fish. Left hand torque tightens the grapple bite on the fish so right hand rotation can be used to release the grapple and come off the fish.

When the fish is properly located in the overshot, exert an upward pull. The grapple shall be contacted by the upward taper in the bowl and the fish held securely. The pack-off rubber seals around the fish, enabling fluid to be forced down through the fish.

Before the start of releasing operations, the weight of the fishing string should always be bumped down, to put the neutral point at the grapple.

The grapple can be freed from the bowl by lowering the string weight or bumping down against the fish. By slowly rotating to the right and slowly raising the string, the spiral grapple unwinds or the basket grapple expands disengaging the string from the fish.

12.6.5 Spears

Spears should be dressed with a pack-off rubber to circulate when required. A stop ring or stop sub should be used to prevent the spear from entering too deeply into the fish. Using these also enables setting of the jars and easier release of tool.

The fishing string should be bumped down before commencing the operation to release the spear. After the hold on the fish is broken, rotate to the right while pulling the string. The left-hand wickers on the spear slips or grapple should then screw the tool off the fish.

A circulation sub should be installed in the fishing assembly when smaller spears are used.

Procedure to Engage and Pull the Fish

To engage and pull the fish:

1. Circulate with the spear a few feet above the top of the fish. Once clean, cut the pump back (stop pump if pack-off is installed) and lower the spear into the fish.
2. Rotate the string to turn the tool one half to one full rotation to the left to set the spear. Left-hand rotation turns the mandrel of the tool through the grapple, setting it in its engaging position.
3. The fish can now be pulled as this should wedge the grapple into a positive engagement on the fish.

Procedure to Release the Fish

To release the fish:

Bump down (maximum allowable) weight of the fishing string. This breaks the engagement. Rotate two or three turns to the right and pick up the string until the spear is clear of the fish.

1. Right-hand rotation moves the mandrel up through the grapple forcing the grapple down against the release ring and puts the spear in the release position.
2. If the spear does not release, bump down while simultaneously rotating to the right and picking up the string until the spear is clear of the fish.
3. If the spear still does not come free, use of the surface jar should be considered depending on the depth of the top of fish.

12.6.6 Washover Strings

Washover strings may be used in the following situations:

- Where the formation has bridged-off and stuck the string.
- Where the string has become cemented in the hole.
- Dressing the top of the fish for latching on with an overshot

General Considerations

The considerations below should be considered when preparing to use a washover string:

Preparation	General Guidelines
Shoe Selection	• Inside casing: hard facing only on the bottom and inside the shoe so that it does not cut on the outside diameter • Open hole: hard facing can be on the inside and outside. Washing over in open hole should only be considered in exceptional circumstances
Safety Joint and Drive Sub	• A safety joint and drive sub should be installed above the washover string to release the string if the washover string becomes stuck
Number of Joints	• Number of joints run depending on the hole inclination and Dog Leg Severity
Rotation	• Low RPM and weight should be used during washovers to reduce the possibility of splitting or flaring the shoe

Table 82. Preparation of Washover String

Reciprocate pipe periodically in order to monitor torque build-up and string resistance.The washover string should be kept in motion as much as possible to prevent sticking.

A junk sub should be installed above the washover string if stabiliser blades are to be washed over.

The mud may be "slicked up" by adding lubricants or changing mud rheology, allowing for hole cleaning requirements..

12.6.7 Junk Retrievers

The two main types of junk retrievers used in fishing operations are the coring type basket and the reverse circulation junk basket or jet retriever. These are described in the table below.

Junk Basket Type	Description
Coring Type	The coring type basket cuts a short core. As the core is being cut, junk is forced into the barrel of the tool. When enough penetration has been made to retrieve the fish, stop rotation and circulation and break the core. The upper and lower catchers of the tool maintain the core in place. POOH.
Reverse Circulation	Mud is diverted through jets by pumping a drop ball from surface causing the mud to be directed outward and downward from the body of the tool. Once the junk has been washed into the tool, catch fingers prevent it from dropping out. This type of junk basket may also be available with a coring shoe.

Table 83. Junk Basket Types.

12.6.8 Miscellaneous Fishing Tools

The following miscellaneous fishing tools may be used.

Tool	Usage
Lead Impression Blocks	• Used if additional information regarding the top of the fish is needed
Rope Spears	• Used to fish broken wireline from the hole • A stop ring should always be run with a rope spear to prevent the spear from passing too far past the top of the wire rope • After the tool has entered the wire rope, it should be rotated one or two turns only and overpull should be taken until the line comes free or breaks at the weak point
Taper Taps and Die Collars	• These tools are difficult to release once engaged and therefore a safety joint and jar must be run with them. They should generally only be run as a last resort. External fishing tools and spears should be run first • Taper taps and die collars must only be run by experienced personnel and extreme care must be exercised when they are used to avoid sticking the entire string
Junk Subs	• Consideration should be given to running junk subs in drilling or milling strings when required

Table 84. Miscellaneous Fishing Tools and their Use.

12.7 CURING LOST CIRCULATION

Lost circulation or lost returns are the loss, to the formation, of either drilling fluids or cement slurry while drilling or completing wells.

The recommended lost circulation material (LCM) that may be used across reservoirs and other formations without causing formation damage is normally Enerseal super fine or its equivalent, Sandseal. Quantities shall be determined on site, and returns are carefully monitored. If formation damage is not a concern other types of LCM (eg. Mica) may be used.

LCM can be used either in concentrated slugs, to deal with more severe losses or as a general drilling fluid treatment to treat seepage/minor losses. When seepage losses increase to more than 20 bbls/hour, an LCM pill may be required to provide more effective prevention than can be achieved by circulating LCM in the drilling fluid.

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

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

12.8 DIFFERENNTIAL STICKING

Differential sticking of drill pipe/collars occurs when the hydrostatic fluid pressure in a wellbore exceeds the formation pore pressure across the interval where the pipe is stationary.

In permeable formations, the drill pipe/collars block the flow of fluid from the wellbore into the formation. This flow, which can be considerable, usually results in the build up of a thick filter cake across the permeable zone. When the drill pipe/collars have been left stationary, such as during connections or when a survey is taken, the surface of the BHA along with the sealing effect of the filter cake forms an effective block reducing fluid loss to the formation.

Depending on the length of the blocked area and the differential pressure between the borehole and formation, this blockage can cause extremely high forces to build up against the drill pipe/collars resulting in the BHA becoming differentially stuck as shown in Figure 30.

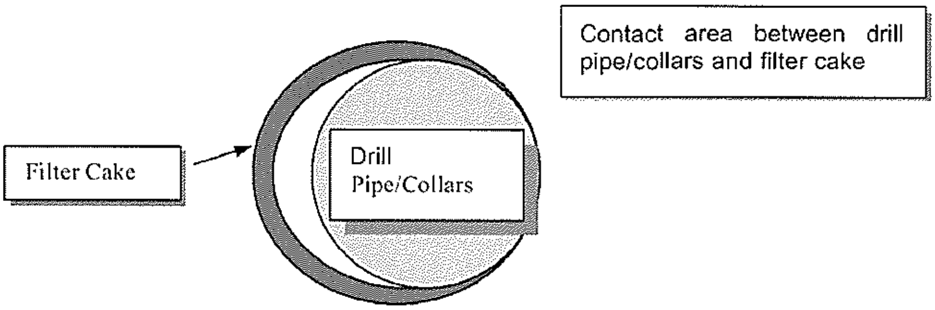


Figure 30. Illustration of Differential Sticking

Full circulation and no up/down mobility or rotary freedom, other than pipe stretch and Torque, are primary indications of differential sticking.

For differential sticking to occur, the following two conditions must exist:

- The hydrostatic pressure of the mud exceeds the pressure of the adjacent formation.
- The formation is porous and permeable (usually sandstone) at the point where the pipe is stuck.

The following conditions can result in differentially stuck pipe:

- High overbalance pressures
- Thick filter cakes
- High-solids mud
- High-density mud
- Significant pressure depletion of reservoirs

When filter cake builds-up on the formation, it increases the contact area between the wellbore and the drill pipe. Excessive drill solids and a high fluid loss increase filter-cake thickness and the coefficient of friction, making it difficult to pull or jar the drill pipe free.

If the pipe does become stuck, every effort should be made to free it immediately. The probability of freeing stuck pipe decreases rapidly with time. Early identification of the sticking mechanism is crucial, since each cause must be solved with a different measure. An incorrect solution can easily make it worse. Typically an evaluation of the events leading up to the stuck pipe incident usually indicates the cause which can lead to proper corrective measures.

Depending on the area and the severity of the pressure depletion, one or several of the following methods may reduce the chance of stuck pipe across the depleted zone. All of the conditions associated with differentially stuck pipe cannot be eliminated, consequently no unique solution exists that can be applied in all areas.

12.8.1 Preventative Measures

While drilling through areas of known pressure depletion:

1. Educate drillers so they are aware of what immediate action is required in the event of tight hole/differential sticking problems.

2. In open hole keep the pipe moving at all times.

    - Reciprocating is the preferred method as it allows you to monitor overpulls. If possible, always begin pipe motion in a downward direction.
    - While making connections minimise the time in which the drill pipe is stationary. (Rotate pipe as long as possible).
    - During well control situations, if possible close annular BOP's and reciprocate drill pipe. Obtain approval to close annular BOP's from rig contractor prior to spud.

3. Minimise the contact area of the BHA in the wellbore.

    - Use spiral drill collars and minimise unstabilised sections of the BHA. Spiral drill collars have a smaller contact area with the wall of the hole and allow fluid passage and equalising of hydrostatic fluid pressure.
    - If hole drag is not a problem, consider using under-gauge stabilisers on drill collars to keep them away from the borehole wall. The use of a packed hole assembly can reduce the number of situations that result in differential sticking by holding the drill string off the wall of the hole. Another unrelated benefit to running bit stabilising assemblies is the prevention of sudden hole angle changes (offsets and doglegs), which can lead to key seats.
    - Only run the minimum length of drill collars to provide the required bit weight. Use heavy weight drill pipe instead of long sections of unstabilised drill collars.

4. Do not program any non-essential surveys. However if surveys are required, they should be dropped prior to POOH rather than run on wireline.

5. If known depleted reservoirs have to be drilled through to reach and evaluate undepleted reservoirs, casing off of the depleted reservoirs may be necessary to avoid acute drilling problems.

12.9 AIR DRILLING

Air may be the circulating medium for drilling some wells in GSLM areas of operation.

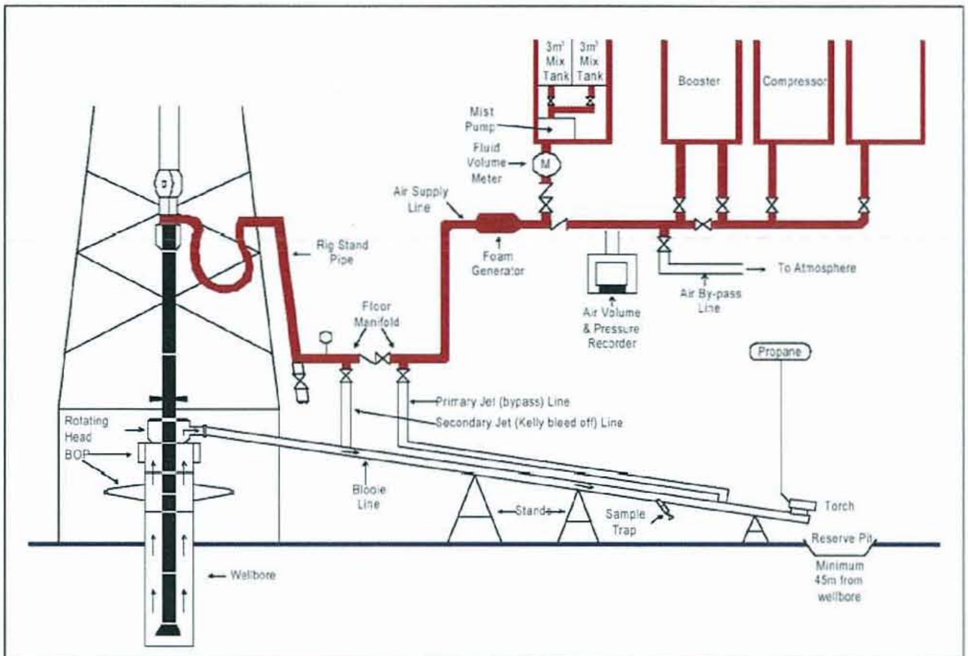


Figure 31. Typical Air, Mist or Foam Drilling layout

The following general guidelines shall be adhered to whilst air drilling:

- A chart type pressure recorder is critical to monitor air pressure effectively. The recorder should be immediately downstream of the air compressors.
- It is essential to have air circulating around the bit before starting drilling. This prevents initial cuttings build-up which is a significant cause of stuck pipe, and prolongs bit life by cooling bearings and cleaning cuttings from the bit.
  Drilling should not begin after a connection until one of these two conditions is met.
- In order to prevent the drill string from becoming stuck as a result of pulling into and packing dry drill cuttings, never pull on the string without air circulation.
- No upper air volume limit has been established for air drilling. However, a frequent cause of failure while drilling with air is insufficient air volume to clean the hole efficiently under a varied range of drilling conditions. The air drilling contractor shall provide field data to establish the optimum values.
- Drill cuttings not removed fall back and bridge when connections are made. Should this occur, options to overcome the problem are:
  - Increase air volume.
  - Always blow the hole until the air and mist returns are clean, before making connections.

Appendix I: Stuck Pipe Analysis - Identifying Causes

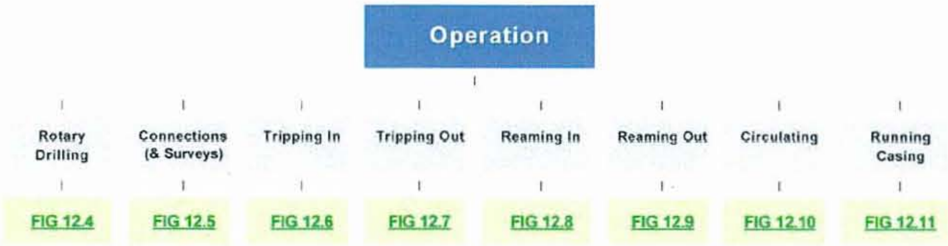


Figure 32. Stuck pipe Analysis – Identifying Causes

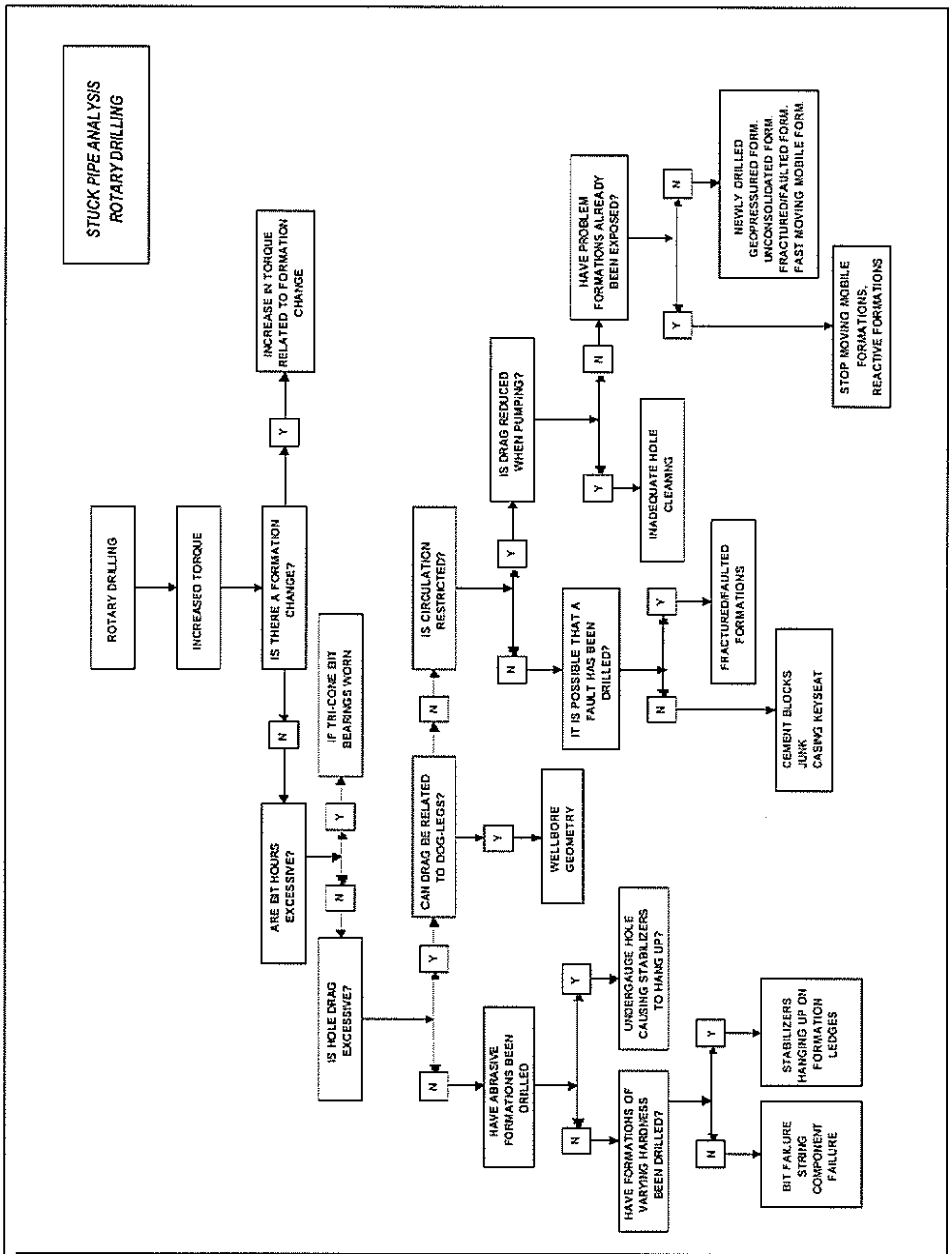


Figure 33. Stuck Pipe Analysis – Rotary drilling

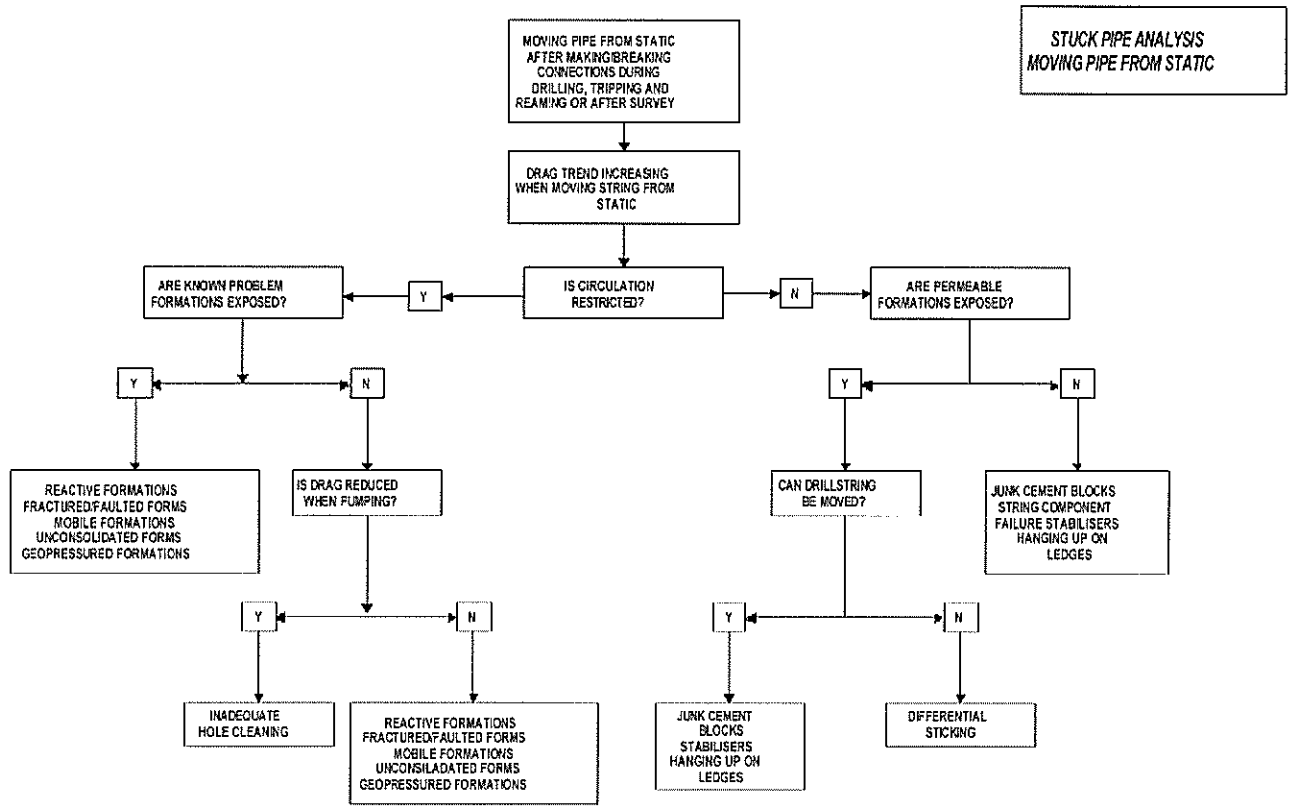
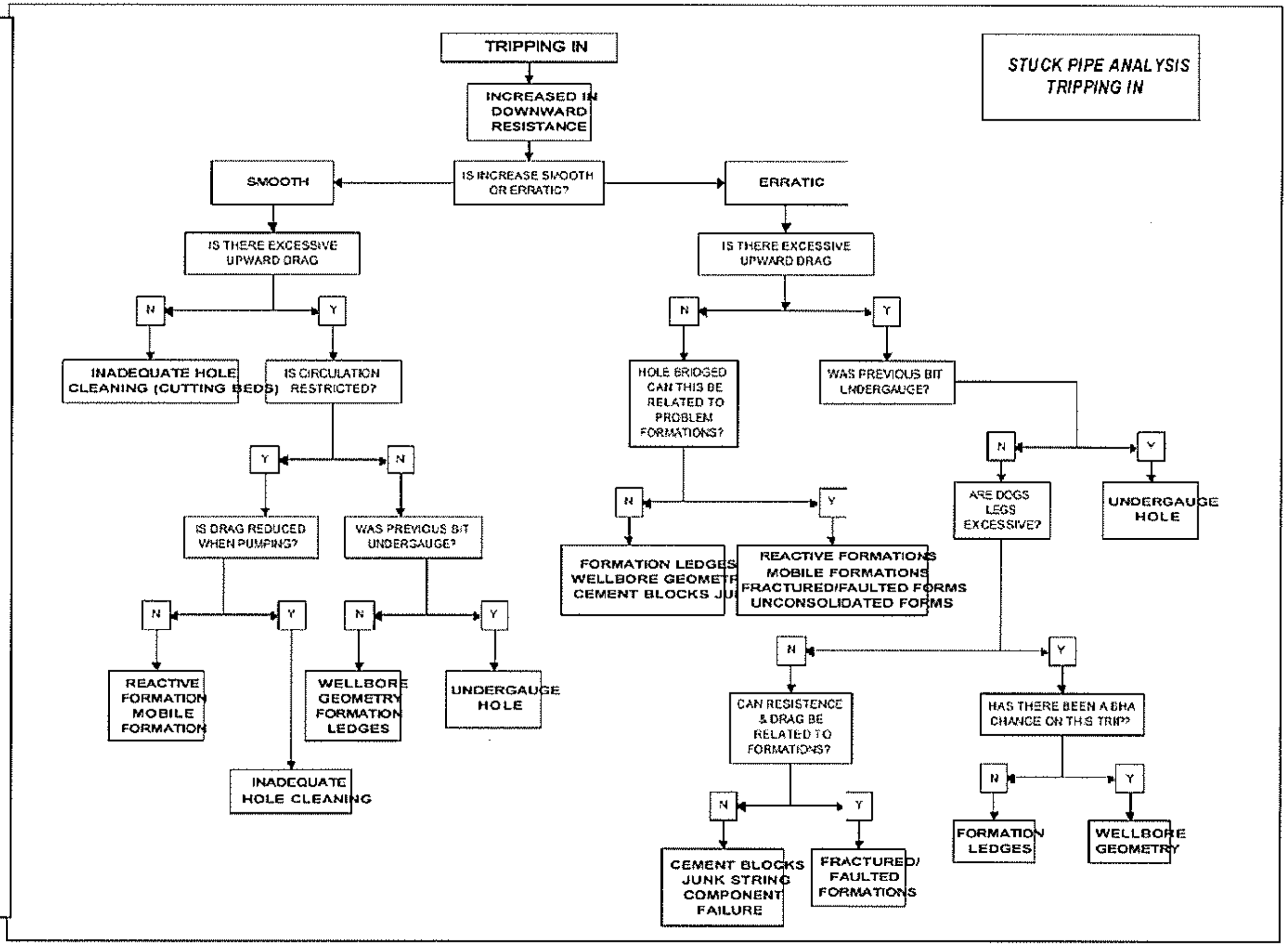


Figure 34. Stuck Pipe Analysis – Moving Pipe from Static

Figure 35. Stuck Pipe Analysis – Tripping In



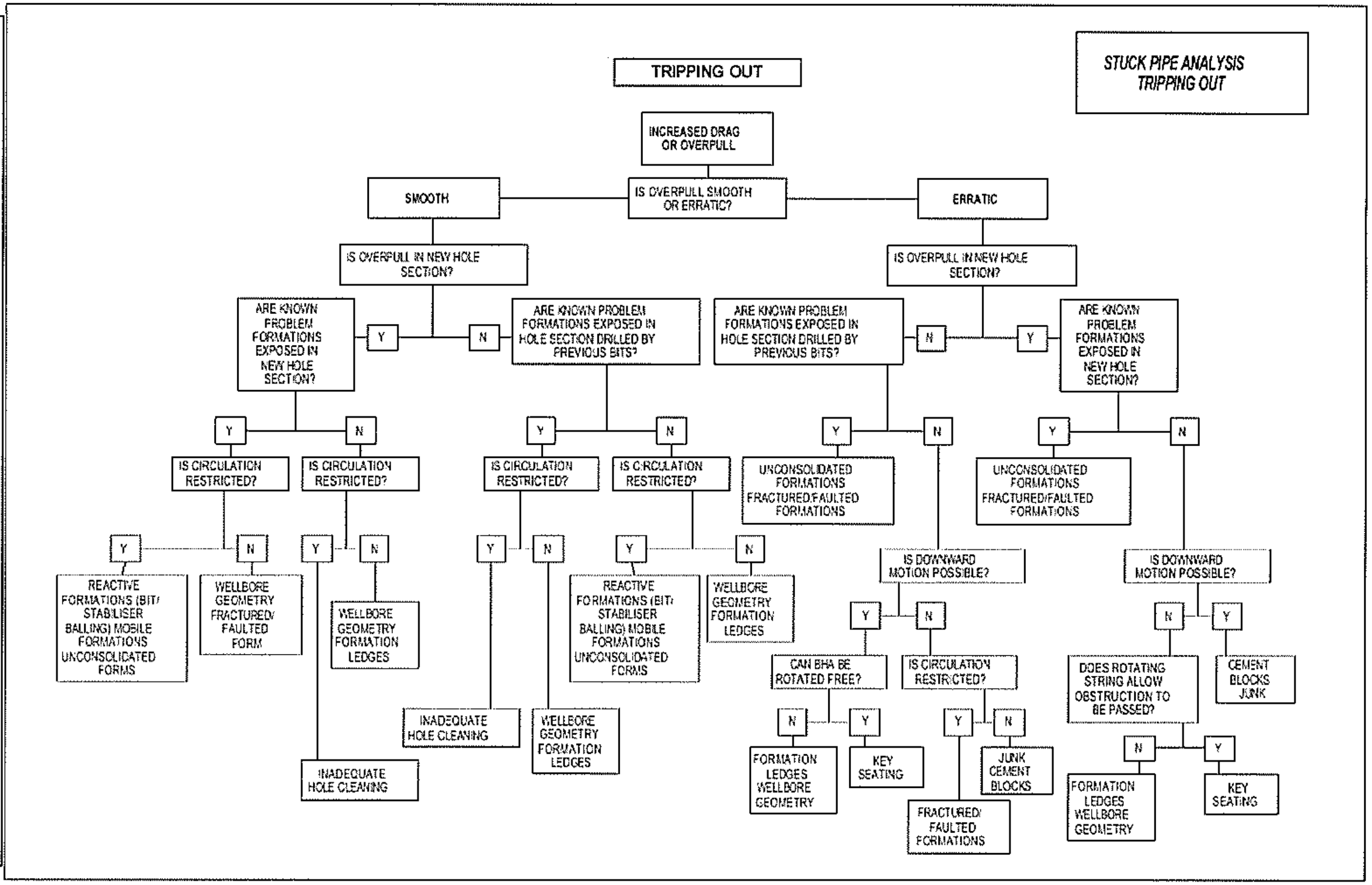


Figure 36. Stuck Pipe Analysis – Tripping Out

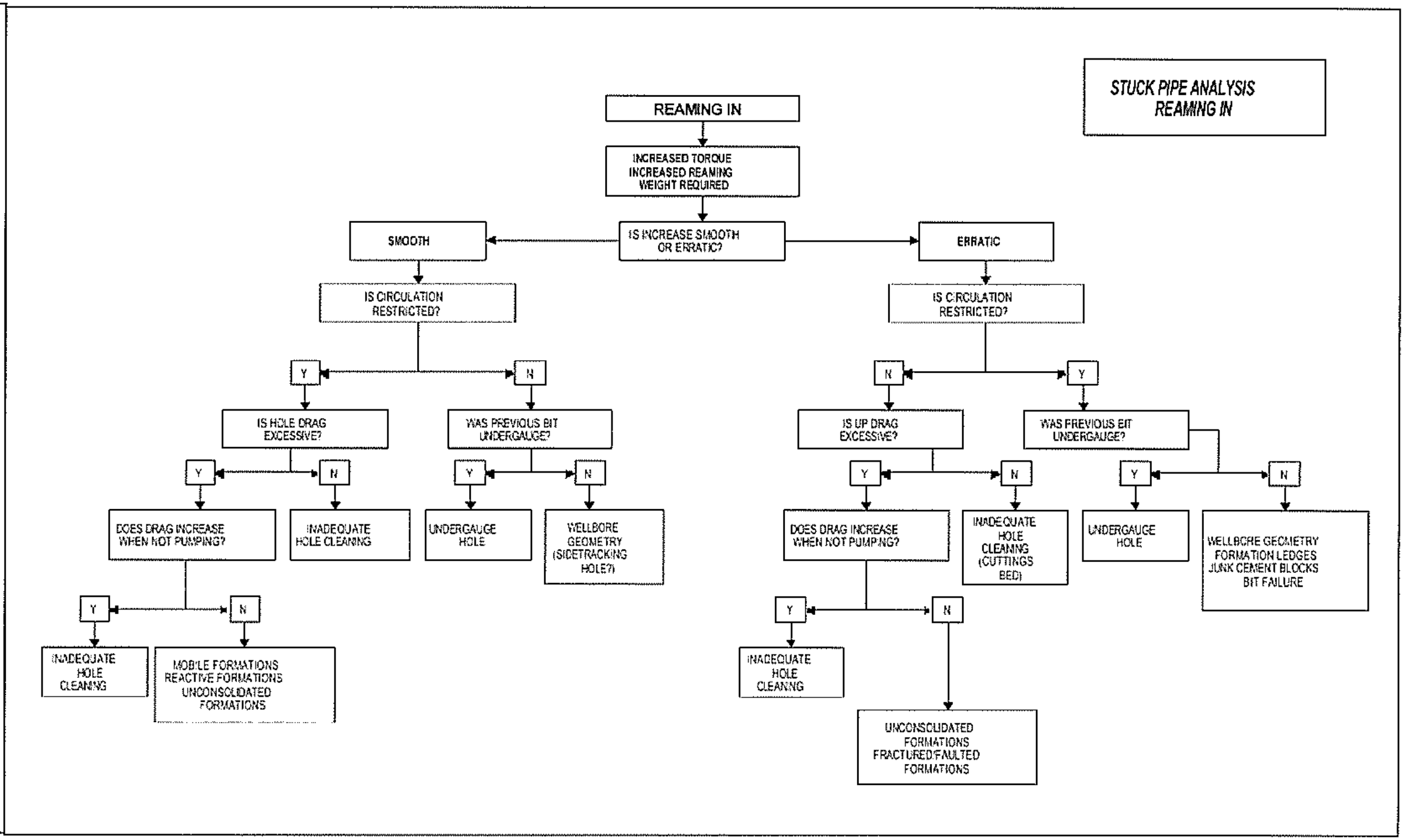


Figure 37. Stuck Pipe Analysis – Reaming In

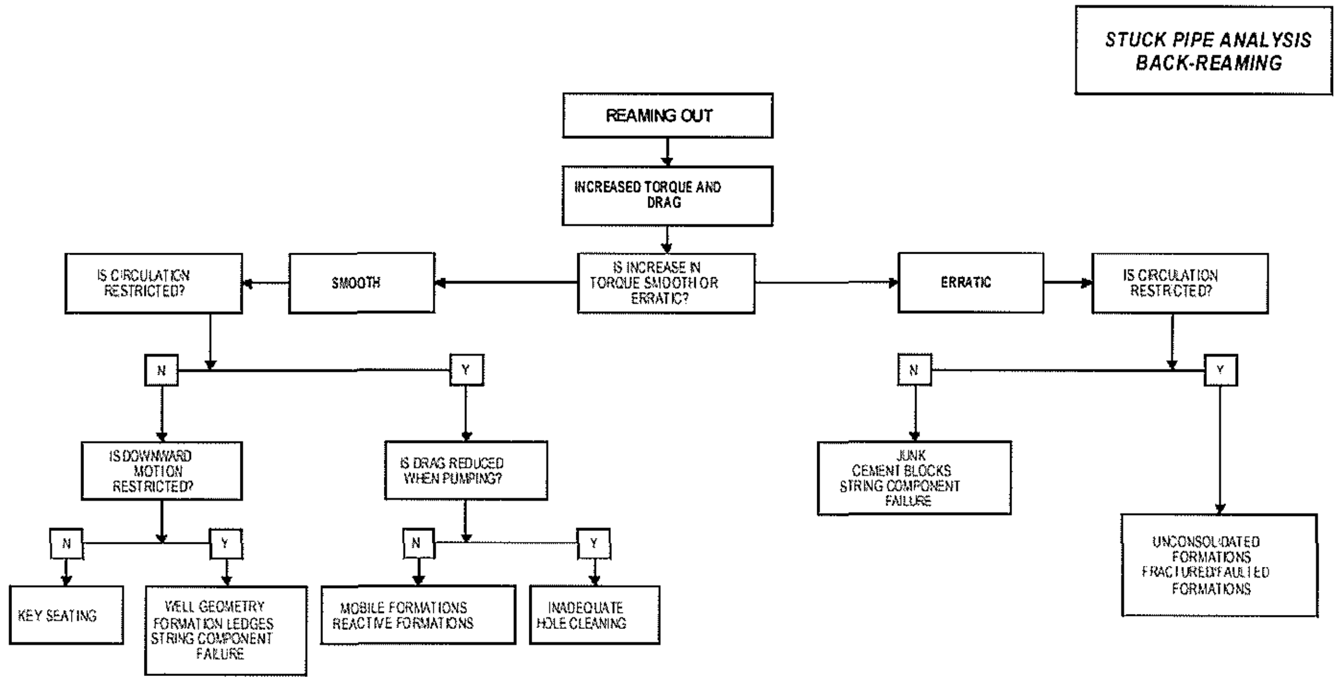


Figure 38. Stuck Pipe Analysis – Back Reaming

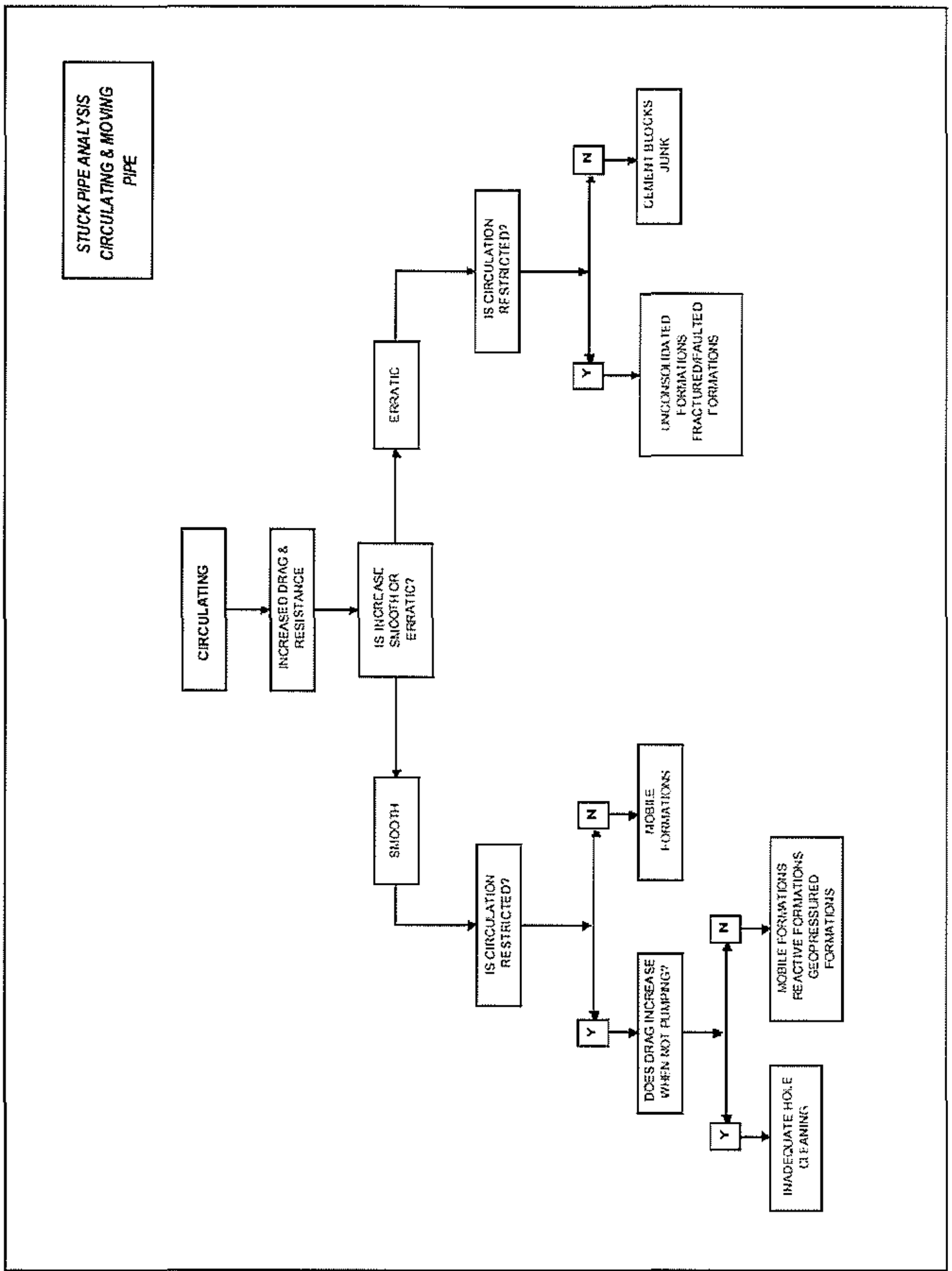


Figure 39. Stuck Pipe Analysis - Circulating

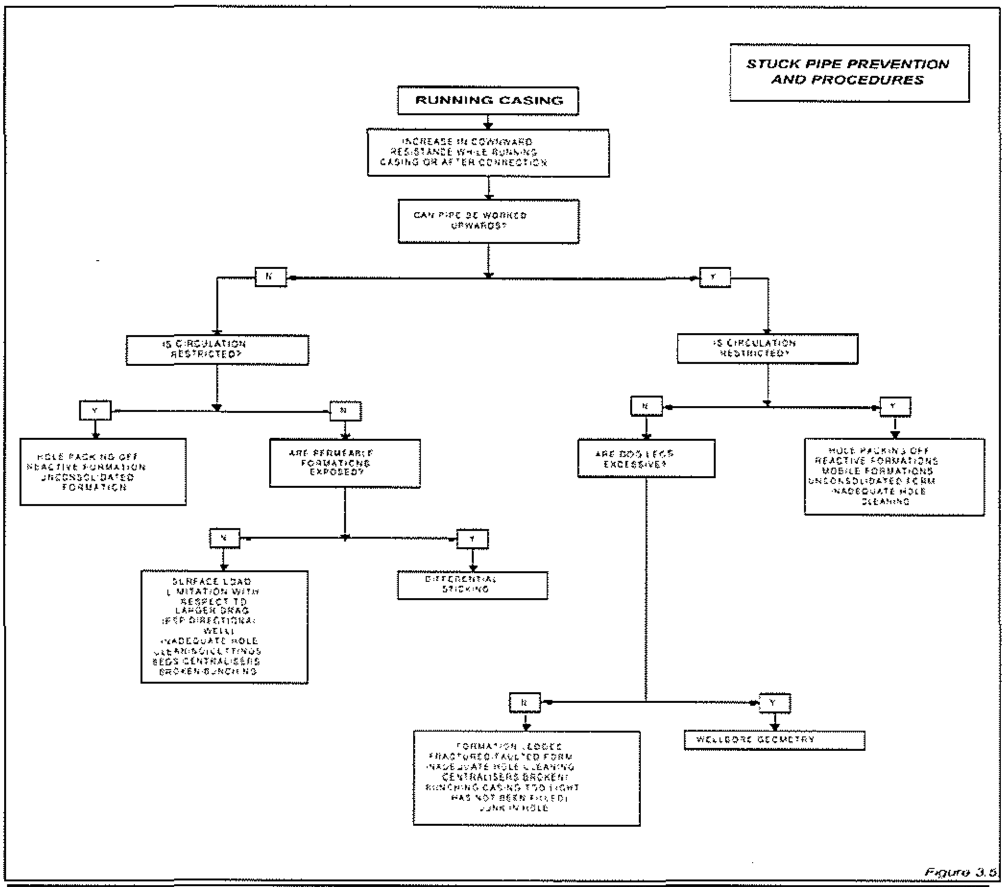


Figure 40. Stuck Pipe Analysis – Running Casing

CHAPTER 13
HAZARDOUS MATERIALS HANDLING

TABLE OF CONTENTS

13.1 OBJECTIVES

The primary objectives of these procedures for hazardous materials handling during drilling operations are to ensure that:

- All personnel involved in the supervision of, or direct handling of hazardous materials, are fully aware of their responsibilities and comply with Government regulations and GSLM policies.
- The primary areas of risk to personnel in the direct and indirect handling of hazardous materials are known and understood.
- Adequate measures shall be taken to prevent or minimise risks asociated with handling hazardous materials.

📖 Occupational Health, Safety and Welfare Act 1986, Explosives, Sections 5.12.25 to 5.12.51

13.2 RESPONSIBILITIES

Responsibilities for the reciept, storage, maintenance and handling of hazardous materials and equipment at the wellsite are summarised in the table below.

Task	Performed by	Verified by
Authorisation of receipt of materials at wellsite	DSV	DSV
Storage of drilling fluids chemicals	Drilling Fluids Contractor	DSV
Maintenance and handling of drilling fluids chemicals	Drilling Fluids Contractor	DSV
Receipt, storage, maintenance and handling of radioactive materials and equipment	Electric Logging Contractor	DSV
Receipt, storage, maintenace and handling of explosives	Electric Logging Contractor	DSV
Receipt, storage, maintenance and handling of hazardous chemicals	Drilling Fluids / Electric Logging Contractors	DSV
Receipt, storage, maintenance and handling of other contractor materials	Relevant Contractor(s)	DSV

Table 85. Responsibilities for Receival, Storage and Handling of Materials at Wellsite

13.3 RADIATION

The following section describes the principles and guidelines for the use of radioactive materials and the hazards associated with their handling.

13.3.1 Radiation Principles and Guidelines

The primary reference document for the use of radioactive sources for wellsite operations is the Schlumberger Radiation Control Manual, or alternative Electric logging Contractor's equivalent.

Operations involving the use of radioactive materials shall only be performed by fully trained and competent personnel. These personnel will follow the correct operational and safety procedures, in order to minimise the hazards and avoid significant risk to personnel and the environment.

Certain operations (e.g. radioactive tracer jobs) involve the use of unshielded radioactive fluids, and in such operations the risk of contamination co-exists with that of irradiation. For these operations, additional, special procedures shall be implemented to ensure safety.

🕮 Schlumberger Radiation Control Manual (or alternate Logging Contractor's equivalent)

13.3.2 Radiation Hazards

Ionising radiation cannot be detected directly by humans. Biological effects of radiation are:

- Massive instantaneous doses kill in a short time.
- The same total doses over a longer period can cause cancer and eventual death.

The above effects require that protection from ionising radiation includes the control of the total cumulative doses received, as well as checks on short term exposure at high dose rates.

All workers who may be exposed to occupational radiation shall be controlled and protected by a monitoring system which records their doses. The DSV shall ensure that the ALARPP syatem (As Low As reasonably Possible) shall be applied in order to provide the most effective control of radiation.

- Minimise field strength through shielding of sources and maintaining maximum distance.
- Minimise time of exposure.
- Set strict limits of acceptable dosage for various categories of workers who may be exposed to radiation, and monitor their cumulative doses.
- Strictly control access of all personnel to areas subject to radiation.

All Wireline Company personnel must wear approved film badges or dosimeters when handling radioactive sources.

13.3.2.1 Radiation Hazard Controls

The DSV shall ensure that only specifically trained and certified personnel are permitted to work with radioactive materials. At the wellsite this is usually the Electric Logging Contractor's engineer and other suitably qualified members of the logging crew. No unqualified person is permitted to work on, approach or in any way interfere with radioactive tools or protective radioactive container.

Exposure to ionising radiation is minimised by effective shielding. Different types of radiation have different shielding requirements. This is stated on the documentation arriving at the wellsite with the hazardous goods. It is the responsibility of the DSV to ensure all such documentation accompanies the goods.

Emergency shielding from gamma rays shall be achieved by the use of sacks of barite weighting material (i.e. when the source cannot be readily detached from the logging tool). Emergency shielding from neutron sources shall be achieved by immersing the source in a 55 gal drum filled with drilling fluid.

13.3.2.2 Storage and Control of Radioactive Materials

It is the responsibility of the DSV to ensure the correct storage of radioactive materials at the wellsite. Permanent storage facilities shall be provided for the storage of radioactive material.

The Electric Logging Contractor shall provide a dedicated radioactive storage container, which shall be used and controlled at the location as follows:

- The permanent store shall be located in a marked area on the location, away from normal personnel access, where the radiation level shall not exceed 1.0 μSv/hour at the perimeter of the marked out area.
- The storage facility shall be secured with a padlock, controlled by the radiation qualified personnel.
- The standard trefoil radioactive warning sign shall be exhibited on the storage container.

13.3.2.3 Transport of Radioactive Sources

The Electric Logging Contractor shall be responsible for transporting radioactive materials in appropriate vehicles and in the correct manner to and from the wellsite. Shuld any source be lost or damaged in transit, it shall be the contractor's responsibility to notify the DSV and the relevant authorities and make the necessary arrangements for recovery.

13.4 EXPLOSIVES

The following section describes the handling, storage, transport and basic safety requirements for explosives on the wellsite

13.4.1 Explosives used in Drilling Operations

Chemical explosives used in wireline activities are divided into two main categories: Low and High Explosives. The latter are subdivided into primary (1°) and secondary (2°) explosives. These are described in the table below.

Explosive		Detonated by	Handling and Storage
Deflagrating or Low Explosives		Exposure to heat or flame	• Suitable for sample takers and bullet guns • May be transported with secondary (2°) explosives but not with primary (1°) explosives
Detonating or High Explosives	1°	Hot wire, flame or percussion	• Extremely sensitive to stray electrical current, electromagnetic transmission (microwaves, radio transmissions), friction and impact. Can be detonated by any small disturbances. • Store in properly grounded containers, handle only by properly trained personnel at wellsite
	2°	High energy shock wave provided by High Explosives	• Extremely insensitive. Relatively safe to handle

Table 86. Categories of Explosives used in Drilling Operations

13.4.2 Transportation of Explosives

Road transport of explosives is controlled by the Electric Logging contractor. The contractor shall be responsible for obtaining all necessary permits to import, store and transport explosives. The following must be adhered to:

- Explosives shall be securely stored and held in the vehicle, in wooden lined containers. Detonators shall never be transported in the same containers as explosives.
  Up to 25 Kg of explosives may be carried in the same vehicle as detonators, provided these are contained in an adequate, grounded separate container.
- Explosives transport containers shall only contain designated explosives.
- Loaded perforating guns shall be securely fastened to the floor of the vehicle.
- The vehicle shall carry prominent explosives warning notices in compliance with legislation.
- Smoking is strictly prohibited in and within the vicinity of a vehicle carrying explosives.
- Vehicles transporting explosives shall carry a minimum of two persons, one of whom shall be trained and certified in the handling of explosives.
- Vehicles designated for transprt of explosives should be diesel powered.
- Vehicle refuelling should be avoided wherever possible. If unavoidable, maximum care should be exercised while refuelling.

- All road journeys shall be conducted using a suitable journey management control, which requires effective liaison between the Electric Wireline Logging Contractor's despatch office and the wellsite, from departure until arrival.

It is the responsibility of the DSV to ensure that the above guidelines are met, reporting any non conformnce to the DM.

13.4.3 Storage and Handling of Explosives

The electric Wireline Logging Contractor shall provide a dedicated explosives storage container which shall be used and controlled on location as follows:

- The permanent store shall be located in a marked area on the location, away from normal personnel access, and at a safe distance from exhausts, welding equipment and any other source of ignition.
- The storage facility shall be secured with a padlock, controlled by the logging operator.
- Access shall be strictly subject to a Permit to Work system.

The logging operator shall be the sole person permitted access to the wellsite explosives store. The operator and the crew shall be the only personnel permitted to handle explosives at the wellsite. Storage and handling of the different types of explosives must be performed in accordance with the standards given in the table in section 13.4.1. The Logging Contractor shall ensure all necessary certificates of competence are obtained for each logging crew member, which shall be available on request.

The DSV shall ensure that the above storage and handling procedures are adhered to.

13.4.3.1 Handling and Storage of Primary Explosives

Primary explosives shall at all times be kept in a separately dedicated storage container, in accordance with the controls above. The segregation from other explosives shall be such that accidental detonation of primary high explosives cannot induce high order detonation of any other explosives in the same storage facility

Under no circumstances shall explosive devices fitted with primary high explosives be stored, even temporarily, at the wellsite. If any delay in the program requires cessation of operations after guns have been armed, they must be disarmed by the contractor's wireline engineer prior to storage or transportation.

The DSV shall ensure that the above procedures are adhered to.

13.4.4 Basic Wellsite Safety of Explosives

The DSV shall ensure that the following precautions are adhered to at the wellsite during drilling operations:

a) The loading and unloading of secondary high explosives (shaped charges, detonators) in perforating guns, or other explosive devices, shall be performed by the contractors personnel, trained and licensed on logging operations and explosives handling.

b) The arming of any explosive device, with a primary high explosive detonator, shall only be performed by the Logging Contractor's engineer, immediately before introducing the device into the wellbore. Make-up and arming of explosive devices shall be performed in a designated area surrounded by a taped area.

c) During all operations involving explosives, the number of persons present must be kept to a minimum. All personnel not directly involved in the operation shall be excluded from the area of operation, and remain at a safe distance.

d) Underbalanced perforating or perforating in any well requiring pressure control equipment shall be avoided in the hours of darkness, due to the dangers of not detecting a broken strand in the wireline.

e) Adequate precautions should be kept to prevent accidental discharge of electric blasting caps and/or ignitors from currents induced by galvanic currents, radio transmitters etc.

f) Helicopter landing is not permitted whilst the Logging Contractor is handling live explosives. If necessary the explosives operations shall be halted until the helicopter has shut down or departed.

g) Handling of explosives at night is only to be allowed if sufficient lighting is available. Smoking, open fires and naked lights of any kind (exposed incandescent material e.g soldering irons, etc.) are strictly prohibited within the safe distance of explosives and shooting equipment.

h) Electrically initiated detonators are extremely sensitive to electrical energy, both in the form of stray currents and direct electromagnetic radiation. Potential sources of such currents and EM radiation, and the precautions to be taken are tabulated below.

Electrical Energy	Precaution
Faulty equipment/ incorrectly earthed electric generators	Faulty equipment wiring can set off guns at surface. The location and rig wiring shall be checked for damaged insulation, loose wires or hanging cables. Attention shall be given to the earthing of all electrical equipment.
Impressed current cathodic protection systems	All flowline/casing cathodic protection devices shall be switched off for the duration of the operation.
Welding equipment	Electric Arc Welding can cause unacceptable voltage differences or dangerous EMM radiation levels. All arc welding shall be stopped before electrical detonators are connected to guns, and remain shut down until the guns are fired, retrieved and inspected on surface.
Radio transmissions	All radio transmissions in the vicinity of the operation shall be suspended for the duration of the operation (See 'Radio Silence" below).
Static charge build-up of rig structure	No electrically detonated explosives shall be used during periods when threatened by electric storms

Table 87. Precautions when Handling Explosives in the Vicinity of Electricity

All non-essential electricity supplies and equipment which may cause stray currents shall be turned off during perforating operations. When connecting the electrical detonators to the guns and whenever the guns are less than 500 ft below surface, all non essential generators, including the generator of the logging unit, shall be stopped. AC rig generators may be kept operating if required for lighting and rig safety systems.

Prior to initiating any operation with electrically detonated explosive devices, the Logging Contractor's engineer shall connect a voltage monitor between the rig mass and wellhead (casing) to verify that stray currents have been eliminated.

13.4.5 Radio Silence

The DSV shall ensure that the radio silence procedures are enforced whenever operations involving the use of electro-explosive detonators are being carried out. These operations include; perforating, side wall sampling, formation interval testing, explosive backing-off (string shot), explosive cutting and setting of wireline set packers and bridge plugs. Radio shut-down requirements during operations with explosives apply within a 450 m (1500ft) radius of the wellhead.

Logging Operation		Making up or Rigging down and < 60 m (200') below Rotary Table	Explosives > 60 m (200') below Rotary Table	After inspection of retrieved tools and Before loading next, or after firing last charge (whilst still in hole)
A	Perforating, sidewall sampling, FITs (not RFTs), explosive backing-off, explosive cutting	Full radio shut-down Hand held radios and mobile phones collected by DSV	No restrictions	Hand held radios and mobile phones should not be re-issued/ returned.
B	Wireline set packers and bridge plugs	Hand held radios and mobile phones not allowed on rig floor, otherwise no restrictions	No restrictions	No restrictions

Table 88. Radio Silence Procedures during Electric Logging Operations

Receive-only radios can remain in operation during any of the operations listed in the table above. However the back-up UHF transmitter must be switched off while operations defined in 'A' (table above) are being carried out.

No operation defined in the table above shall be carried out during weather conditions which are likely to produce electrical discharges.

13.5 HAZARDOUS CHEMICALS

The following section describes the handling, storage and disposal of hazardous chemicals

13.5.1 Safety Awareness

Every chemical stored or used at the wellsite shall be supplied with a current Materials Safety Data Sheet (MSDS). These shall be filed by the rig toolpusher at the wellsite, and kept in the Toolpusher's office, accessible to all site personnel at all times. The Toolpusher shall ensure that copies of relevant MSDS are issued to each personnel assigned to handle any chemical. The Toolpusher shall also ensure that copies of all MSDS sheets are sent to the nearest Hospital if required.

The relevant health and safety data on drilling fluid chemicals is also summarised on plasticised notices (Safety data Sheets) provided by each Drilling Fluids Contractor, for prominent display on site.

For each product the MSDS includes:

- First Aid information (i.e. relating to swallowing, inhaling or contact with eyes or skin).
- Spills and disposal procedures.
- Personal protection procedures.
- Storage and transport procedures.
- Fire precautions.

13.5.2 Hazardous Chemicals Used

The following two categories of hazardous chemicals are typically used at the wellsite.

13.5.2.1 Drilling and Completion Chemicals

Hazardous drilling and completion chemicals used at the wellsite are categorised as follows:

- PH adjusters.
- Bacteriacides.
- Corrosion inhibitors.
- Bromide Salts for heavy brines

Bromide Salts are not generally used in GSLM activities. However, the handling standards and procedures for hazardous chemicals apply equally to each category.

Not all drilling and completion fluid chemicals are classified as hazardous. However the majority of chemicals cause skin irritation as a minimum effect. All should be handled with care and knowledge, using appropriate levels of personal protective equipment, and in accordance with the relevant MSDS (also reference section 13.5.3).

Note: Of all hazardous drilling fluid chemicals, Caustic Soda (Sodium Hydroxide, NaOH) is the most widely used.
Personnel handling Caustic Soda must be made aware that it takes only a small particle in the eye to cause permanent damage.

13.5.2.2 Other Wellsite Chemicals

Non drilling fluid chemicals used at the wellsite are normally supplied and controlled by the following contractors:

- Electric Wireline Logging Contractor
- Cementing Contractor
- Drilling Contractor
- Mud Logging Contractor

All chemicals should be supplied with MSS. The most significantly hazardous chemical in use is the chemical cutter used by the Wireline Logging contractor, which contains an extremely reactive and toxic chemical. Rigid controls in the methods of storage, handling and application must be in place to ensure that the hazard is fully controlled and presents minimum risk to personnel or the environment.

A copy of the Logging Contractor's Procedures Manual must be available in each logging unit. It is the responsibility of the DSV to ensure that all relevant documentation is available.

📖 Chemical Cutters Procedures in the Schlumberger Procedures Manual, or alternate Logging Contractors equivalent document.

13.5.3 Hazardous Chemicals Handling

The DSV shall ensure that the following personal protective equipment are available at the wellsite and are used by all personnel handling chemicals. The MSDS should state the required protective clothing which may include one or all of the following items:

- Dust respirator
- Chemical safety goggles or glasses
- Face shield
- Hard hat
- Chemically resistant gloves and/or cotton gloves
- Long protective clothing
- Neoprene protective apron
- Impervious safety boots

It is the responsibility of all personnel to ensure they are familiar with the health and Safety data relevant to the chemical(s) they are handling, via the MSDS and the displayed Safety data sheets on site. They should also ensure that safety equipment in their work area (i.e. eye flushes, body showers etc.) are present and functional.

The Safety data sheets (section 13.5.1) provide all necessary information on the treatment of chemical contact of the body.

Operations personnel who are trained and assigned as First Aiders on site, shall also be familiar with the required responses to chemical effects, and shall ensure that specified safety apparatus is available and functioning on site.

13.5.4 Hazardous Chemicals Storage

All chemicals shall be stored in a designated area on pallets, and sufficient water-resistant covers shall be available to protect them in case of rain.

Those chemicals classified as hazardous shall be stacked separately from other chemicals, in a bunded area, and shall have a secure warning notice describing the chemical type(s) and major hazard(s), situated prominently next to them. Protecting these chemicals from rain and floodwater and preventing access by local wildlife, shall be a primary requirement.

13.5.5 Hazardous Chemicals Disposal

The safe disposal methods for both waste chemicals and their empty containers are dependant on the type of chemical, and shall be carried out in accordance with the following:

- Material Safety Data Sheet (MSDS) for each chemical.

CHAPTER 14
WELLHEAD INFORMATION

TABLE OF CONTENTS

14.1 OBJECTIVES

The objective of Wellhead Information is to provide a schematic overview of, and appropriate vendor references to, GSLM wellhead equipment standards as applied to all wells. Reference should also be made to the schematics of wellhead standards for suspension and abandonment in Chapter 11 of this Manual.

14.2 RESPONSIBILITIES

As this Chapter primarily provides a description of wellhead equipment, very few responsibilities have been defined.

Task	Performed by	Verified by
Order wellhead equipment	DM	DM
Confirm wellhead equipment conforms to requirements of Drilling Program.	DSV	DM
Confirm all requited wellhead equipment is on location.	DSV	DM
Callout wellhead technician (if required)	DSV/DM	DM

Table 89. Responsibilities for Wellhead Equipment

14.3 STANDARD WELLHEAD CONFIGURATIONS

The standard wellhead configurations listed below identify the required wellhead assemblies and pressure ratings for wells drilled in Tasmania.

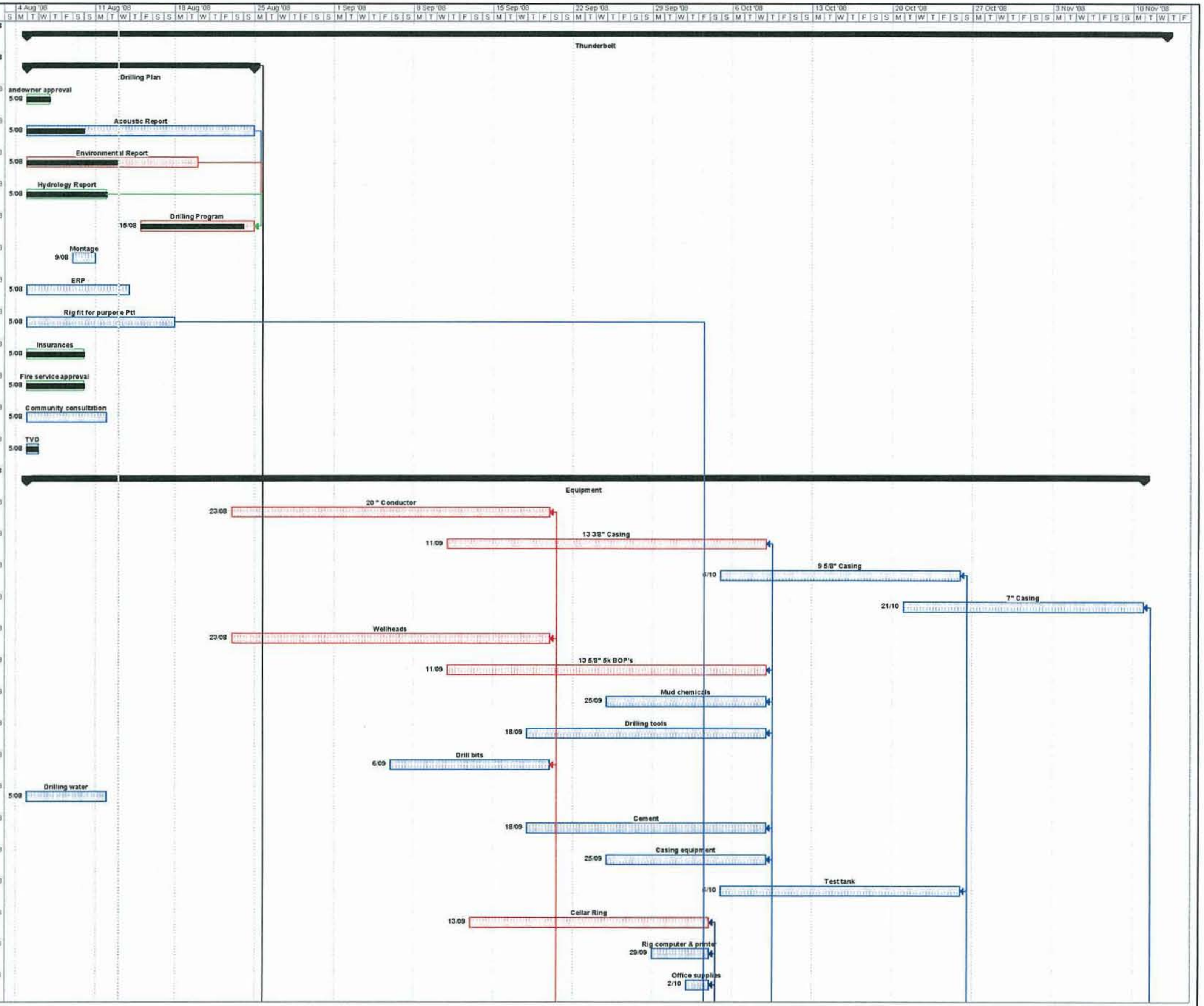
14.3.1 Conventional Wells

Casing Scheme	Pressure Rating
13 3/8" x 9 5/8" x 7"	3000 psi, 5000 psi
9 5/8" x 7"	3000 psi, 5000 psi

Table 90. Standard Wellhead Configurations for Conventional and Downsized Wells

GSLM will utilise API rated wellhead equipment, specified for the service, supplied by recognised wellhead manufacturers, and where possible fabricated and supported by locally based companies (e.g. Wood Group Pressure Control Australia Pty. Ltd, Cameron Australasia Pty. Ltd.). All wellhead equipment will be installed, operated and maintained as per the suppliers documented procedures. The wellhead supplier will supply technical support.

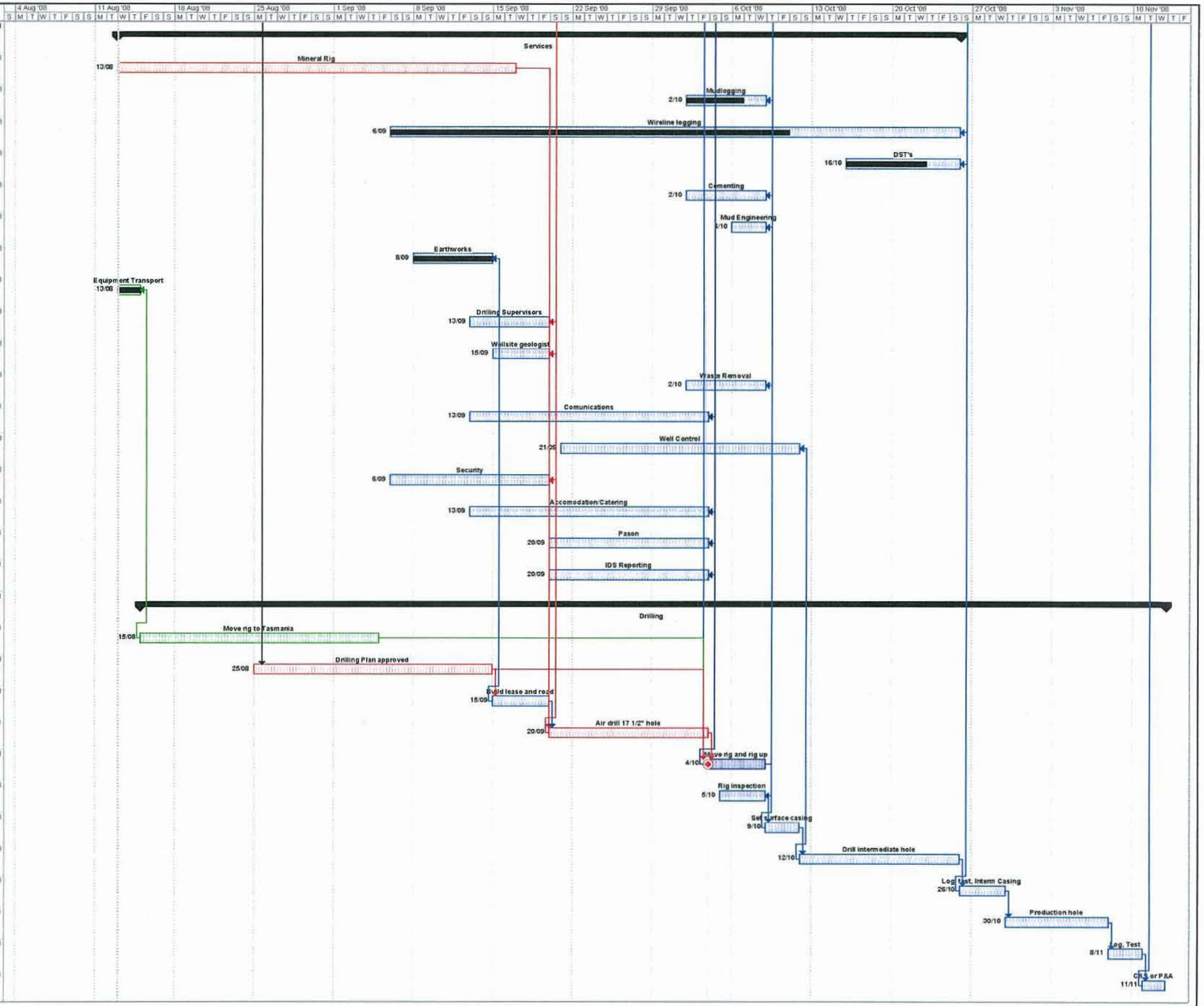
ID		Task Name	Duration	Start	Finish
1		**Thunderbolt**	**72 days**	**Tue 5/08/08**	**Thu 13/11/08**
2		**Drilling Plan**	**60 days**	**Tue 5/08/08**	**Mon 25/08/08**
3	✓	Landowner approval	2 edays	Tue 5/08/08	Thu 7/08/08
4		Acoustic Report	20 edays	Tue 5/08/08	Mon 25/08/08
5		Environmental Report	15 edays	Tue 5/08/08	Wed 20/08/08
6	✓	Hydrology Report	7 edays	Tue 5/08/08	Tue 12/08/08
7		Drilling Program	10 edays	Fri 15/08/08	Mon 25/08/08
8		Montage	2 edays	Sat 9/08/08	Mon 11/08/08
9		ERP	9 edays	Tue 5/08/08	Thu 14/08/08
10		Rig fit for purpose Pt1	13 edays	Tue 5/08/08	Mon 18/08/08
11	✓	Insurances	5 edays	Tue 5/08/08	Sun 10/08/08
12	✓	Fire service approval	5 edays	Tue 5/08/08	Sun 10/08/08
13		Community consultation	7 edays	Tue 5/08/08	Tue 12/08/08
14	✓	TVD	1 eday	Tue 5/08/08	Wed 6/08/08
15		**Equipment**	**70 days**	**Tue 5/08/08**	**Tue 11/11/08**
16		20 " Conductor	28 edays	Sat 23/08/08	Sat 20/09/08
17		13 3/8" Casing	28 edays	Thu 11/09/08	Thu 9/10/08
18		9 5/8" Casing	21 edays	Sun 5/10/08	Sun 26/10/08
19		7" Casing	21 edays	Tue 21/10/08	Tue 11/11/08
20		Wellheads	28 edays	Sat 23/08/08	Sat 20/09/08
21		13 5/8" 5k BOP's	28 edays	Thu 11/09/08	Thu 9/10/08
22		Mud chemicals	14 edays	Thu 25/09/08	Thu 9/10/08
23		Drilling tools	21 edays	Thu 18/09/08	Thu 9/10/08
24		Drill bits	14 edays	Sat 6/09/08	Sat 20/09/08
25		Drilling water	7 edays	Tue 5/08/08	Tue 12/08/08
26		Cement	21 edays	Thu 18/09/08	Thu 9/10/08
27		Casing equipment	14 edays	Thu 25/09/08	Thu 9/10/08
28		Test tank	21 edays	Sun 5/10/08	Sun 26/10/08
29		Cellar Ring	21 edays	Sat 13/09/08	Sat 4/10/08
30		Rig computer & printer	5 edays	Mon 29/09/08	Sat 4/10/08
31		Office supplies	2 edays	Thu 2/10/08	Sat 4/10/08



Project: Thunderbolt 1 Plan Updated 1
Date: Wed 13/08/08

Task | Split | Progress | Milestone | Summary | Project Summary | External Tasks | External MileTask | Split

ID		Task Name	Duration	Start	Finish
32		**Services**	**53 days**	**Wed 13/08/08**	**Sun 26/10/08**
33		Mineral Rig	35 edays	Wed 13/08/08	Wed 17/09/08
34		Mudlogging	7 edays	Thu 2/10/08	Thu 9/10/08
35		Wireline logging	50 edays	Sat 6/09/08	Sun 26/10/08
36		DST's	10 edays	Thu 16/10/08	Sun 26/10/08
37		Cementing	7 edays	Thu 2/10/08	Thu 9/10/08
38		Mud Engineering	3 edays	Mon 6/10/08	Thu 9/10/08
39	✓	Earthworks	7 edays	Mon 8/09/08	Mon 15/09/08
40	✓	Equipment Transport	2 edays	Wed 13/08/08	Fri 15/08/08
41		Drilling Supervisors	7 edays	Sat 13/09/08	Sat 20/09/08
42		Wellsite geologist	5 edays	Mon 15/09/08	Sat 20/09/08
43		Waste Removal	7 edays	Thu 2/10/08	Thu 9/10/08
44		Comunications	21 edays	Sat 13/09/08	Sat 4/10/08
45		Well Control	21 edays	Sun 21/09/08	Sun 12/10/08
46		Security	14 edays	Sat 6/09/08	Sat 20/09/08
47		Accomodation/Catering	21 edays	Sat 13/09/08	Sat 4/10/08
48		Pason	14 edays	Sat 20/09/08	Sat 4/10/08
49		IDS Reporting	14 edays	Sat 20/09/08	Sat 4/10/08
50		**Drilling**	**64 days**	**Fri 15/08/08**	**Thu 13/11/08**
51		Move rig to Tasmania	21 edays	Fri 15/08/08	Fri 5/09/08
52		Drilling Plan approved	21 edays	Mon 25/08/08	Mon 15/09/08
53		Build lease and road	5 edays	Mon 15/09/08	Sat 20/09/08
54		Air drill 17 1/2" hole	14 edays	Sat 20/09/08	Sat 4/10/08
55		Move rig and rig up	5 edays	Sat 4/10/08	Thu 9/10/08
56		Rig inspection	4 edays	Sun 5/10/08	Thu 9/10/08
57		Set surface casing	3 edays	Thu 9/10/08	Sun 12/10/08
58		Drill intermediate hole	14 edays	Sun 12/10/08	Sun 26/10/08
59		Log, test, Interm Casing	4 edays	Sun 26/10/08	Thu 30/10/08
60		Production hole	9 edays	Thu 30/10/08	Sat 8/11/08
61		Log, Test	3 edays	Sat 8/11/08	Tue 11/11/08
62		C&S or P&A	2 edays	Tue 11/11/08	Thu 13/11/08



Project: Thunderbolt 1 Plan Updated 1 Date: Wed 13/08/08	Task	Split	Progress	Milestone	Summary	Project Summary	External Tasks	External MileTask	Split

ID	Task Name	Duration	Start	Finish
1	**Thunderbolt**	**72 days**	**Tue 5/08/08**	**Thu 13/11/08**
2	**Drilling Plan**	**68 days**	**Tue 5/08/08**	**Mon 25/08/08**
3	Landowner approval	2 edays	Tue 5/08/08	Thu 7/08/08
4	Acoustic Report	20 edays	Tue 5/08/08	Mon 25/08/08
5	Environmental Report	15 edays	Tue 5/08/08	Wed 20/08/08
6	Hydrology Report	7 edays	Tue 5/08/08	Tue 12/08/08
7	Drilling Program	10 edays	Fri 15/08/08	Mon 25/08/08
8	Montage	2 edays	Sat 9/08/08	Mon 11/08/08
9	ERP	9 edays	Tue 5/08/08	Thu 14/08/08
10	Rig fit for purpose P11	13 edays	Tue 5/08/08	Mon 18/08/08
11	Insurances	5 edays	Tue 5/08/08	Sun 10/08/08
12	Fire service approval	5 edays	Tue 5/08/08	Sun 10/08/08
13	Community consultation	7 edays	Tue 5/08/08	Tue 12/08/08
14	TVD	1 eday	Tue 5/08/08	Wed 6/08/08
15	**Equipment**	**70 days**	**Tue 5/08/08**	**Tue 11/11/08**
32	**Services**	**53 days**	**Wed 13/08/08**	**Sun 26/10/08**
50	**Drilling**	**64 days**	**Fri 15/08/08**	**Thu 13/11/08**
51	Move rig to Tasmania	21 edays	Fri 15/08/08	Fri 5/09/08
52	Drilling Plan approved	21 edays	Mon 25/08/08	Mon 15/09/08
53	Build lease and road	5 edays	Mon 15/09/08	Sat 20/09/08
54	Air drill 17 1/2" hole	14 edays	Sat 20/09/08	Sat 4/10/08
55	Move rig and rig up	5 edays	Sat 4/10/08	Thu 9/10/08
56	Rig inspection	4 edays	Sun 5/10/08	Thu 9/10/08
57	Set surface casing	3 edays	Thu 9/10/08	Sun 12/10/08
58	Drill intermediate hole	14 edays	Sun 12/10/08	Sun 26/10/08
59	Log, test, Interm Casing	4 edays	Sun 26/10/08	Thu 30/10/08
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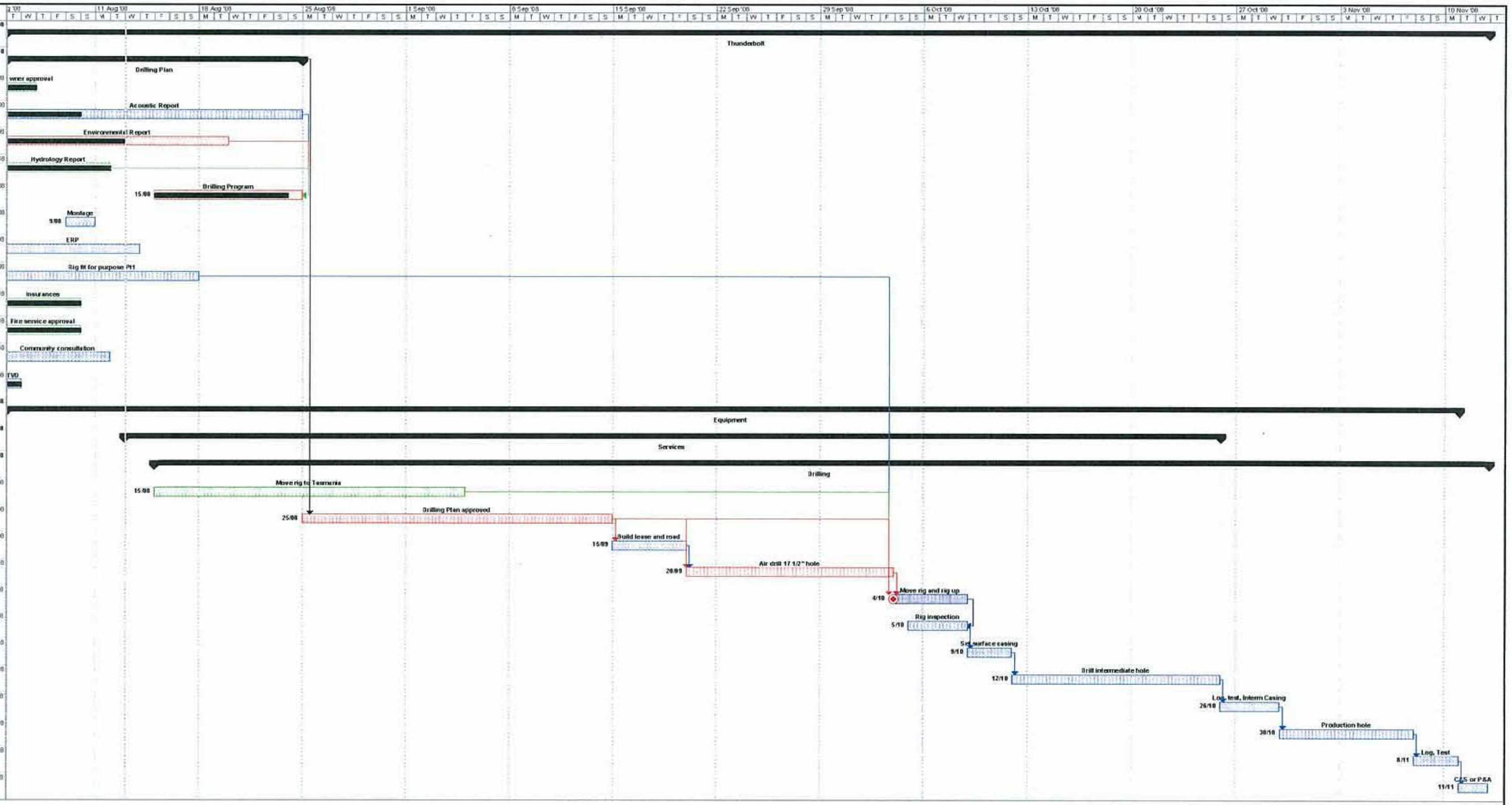
61	Log, Test	3 edays	Sat 8/11/08	Tue 11/11/08
62	C&S or P&A	2 edays	Tue 11/11/08	Thu 13/11/08



Project: Thunderbolt 1 Plan Updated 1
Date: Wed 13/08/08

Task | Split | Progress | Milestone | Summary | Project Summary | External Tasks | External MileTask | Split