Drilling Operations Guidelines

Stuck Pipe Prevention, Causation & Freeing

Rev	Date	Description	Compilation	Reviewer
1.1	Nov 2015	Stuck pipe management	Peter Aird	
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1 General Stuck Pipe prevention

1.1 Introduction

There are very few cases of stuck pipe which are impossible to prevent. Many incidents could be avoided by more careful planning or greater care at the rig site.

Among the many people involved in the drilling operation, the Driller has the key position in preventing stuck pipe. Thorough planning, good drilling practices and an effective mud system can ensure that the hole is in the best possible condition.

However, once a problem exists, the only person who can prevent it resulting in stuck pipe is the Driller.

At the instant that the formation grabs the pipe or the hole packs off, it is the Driller's reaction which is all important.

The Drilling Representative(s) and Toolpusher(s) must be sure that every Driller is aware of any special problems and what his immediate actions should be.

The greater the Driller's understanding of the problems, the greater the chance that he keeps the pipe free.

1.1.1 **Stuck pipe is not inevitable.**

Stuck pipe is not inevitable if people.

1. ***Communicate effectively***
2. ***Plan.***
3. ***Listen to the wellbore constantly.***
4. ***Maintain good mud.***
5. ***Keep the pipe moving,***
6. ***Clean the wellbore only as fast as one is drilling it.***
7. ***Do not drill a hole that cannot be readily tripped.***
8. ***Take early action when warning signs and indicators arise.***
9. ***Implement the correct action plan.***

1.1.2 **General**

1. Rig Contractor's personnel should understand and be aware of tight hole and stuck pipe procedures.
2. The BHA design run in all wellbore sections must be based on only the required components that will give the least risk of getting stuck. *E.g. Why have a BHA weighing 80,000lbs when drilling with a PDC at 10-15,000lbs weight on bit.*
3. Be aware of the amount of open-hole time for each section. Any reduction in this will help to cut the chance of stuck pipe.
4. Mud design is critical in keeping a hole in optimum condition. Careful consideration of the mud system and planned mud weight will be rewarded by reduced tight hole.
5. Although the priority for a casing design must be to ensure that the well can be drilled safely, one consideration should be stuck pipe. Without compromising safety, the shoe depth has therefore been planned to case off troublesome formations.

1.2 Rig Site Precautions

1.2.1 Excessive drag

The **primary** reason for **tight hole** and/or **excessive drags** deteriorating to stuck pipe has been due to **IMPROPER PRACTICES, EXCESSIVE OVER PULL OR SET DOWN**-loads applied.

Excessive over pull / set down-loads should only be applied if all other reasonable attempts to work the pipe have failed.

In abnormal drag situations **be patient**. Time spent conditioning mud and the hole is not wasted time but is insurance against greater time lost during stuck pipe incidents.

A Driller may be reluctant to break circulation and disturb the slug, but it is far easier to re-slug the pipe than to free it once stuck. Ensure therefore that the Drillers are aware of what to do if the hole becomes tight and of any expected problems.

At the first signs of abnormal drags, the Company Representative and Senior Toolpusher should be informed.

1.2.2 Excessive Drag Best Practice Guidelines

Limit initial applied overpull or set downloads to: Normal drag +/- the **BHA** weight below the **JAR.**

If no abnormal drags are observed to release the string from the weight applied, incrementally increase the applied weights until abnormal drags are noted.

This establishes the upper limit you can work the drillstring without mechanically sticking the drillstring. If pipe is stuck while POH, initially **work and jar downwards only.** If pipe is stuck while RIH, initially **work and jar upwards only.**

- Keep the drill string moving as much as possible in open hole.
- Circulate sooner than later when tripping if hole conditions are worsening.
- Record all tight spots on trips in/out of the hole.
- Have mud loggers provide a simple formation / depth chart for use while tripping. *(use the offset data)*
- Know the position of your BHA components.
- Acknowledge increasing wellbore drags.

Note: The information provided above aids in developing trends, identify what, why and where you may get stuck and enable you to apply the correct freeing practices for the stuck pipe mechanism at hand. Time spent doing the above will be worth it if a stuck pipe situation should occur, where reaction time will be critical to operational success.

Wash, wipe and/or ream any resistance experienced. Where necessary ream any consistent tight spots a few times. Report if this has no effect. Mud or formation characteristics may be contributing to the problem.

Work and trip pipe at a controlled speed. *Note: As a rule of thumb in 8½" and smaller wellbore sizes pressure effects will more readily result in wellbore problems occurring.*

Wipe the hole *(without rotating)* before making a connection. Note: This is the most effective method to monitor wellbore drags and establish if wellbore conditions are deteriorating.

NEVER force the bit to bottom.

REMEMBER: Prevention is better than the cure. Think about what formation you are drilling, what problems are likely to occur, and how you will handle them.

If a tight wellbore or drags cannot be eliminated during POH, Back ream with caution. *Although this practice is widely used there is no documentation available stating that such practices benefits the drillstring, hole cleaning and/or wellbore stability considerations.*

1.2.3 Open hole Practices

Always exercise caution when tripping in open hole. The Drilling Representative or Toolpusher may wish to be on the floor throughout the newly drilled section and through any problem sections encountered.

Never try to force the string through a tight spot. *Pulling firmly into tight hole, may well lead to the string becoming stuck.*

Take it carefully and do not pull more than half the weight of the collars below the jars. If this rule is followed, it should always be possible to work the pipe back down. *This gives the Driller a figure to work to and will prevent many stuck pipe incidents each year.*

Depending on the situation, the Drilling Representative has the option of gradually increasing the overpull, each time checking that the pipe is free to go down. At any stage, the top drive can be used to wash down and work the pipe.

Never pull more than the weight of the collars, as this will almost certainly result in the string becoming stuck.

Always wash and ream at least the last 3 joints to bottom

Before tripping, always endeavour to sufficiently clean the hole.

Minimise time spent in open hole.

Monitor and record the depths and magnitude of drags, overpull, and any rotary torque *(if rotation was necessary) to* help assess the condition of the hole.

Wiper trips only if wellbore conditions dictate this! E.g. A wiper trip is required due to difficulties pulling out of the well and is decided by the operator at some during drilling, making connections, tripping, or once back into the previous casing shoe. Sometimes a short trip through newly drilled hole may be all that is required if downhole wellbore indicators dictate this.

Drillers / Supervisors must be fully aware and comprehend how the drilling jars work. *The different mechanisms need to be understood because certain situations may arise which require that knowledge. For example, daily mechanical jar settings change with torque, while hydraulic jars have an infinite number of settings depending on the pull.*

If the string is pulled to the maximum and mechanical jars do not go off, it may be that the amount of overpull needed for the jar to hit has not been reached.

With hydraulic jars, it would mean that either the string would be stuck above them or that the tool had failed.

The Drillers and Supervisors must know how each set of jars works to make decisions from this point. *Any relevant information should be passed to the Driller.*

The shale shakers should be monitored regularly by the drilling Crews, Mud loggers, Mud Engineer and Drilling Representative. The shape, quantity, and trend condition of the cuttings at the shakers provided a valuable insight and indications to what is happening downhole. Personnel must be assigned to check the shakers at frequent intervals and this practice must be continued.

1.2.4 Top drives

Top drive units are a successful development in reducing stuck pipe incidents. It permitted stands to be run, pulled and circulated/ream versus singles permissible with a Kelly drive rig.

It must be recognised that with Top drives, very ***different drilling technique*** require far more special purposeful and well-reasoned procedures and guidelines with the same amount of care.

Problems peculiar to top drives, have doubtless been identified by all operations which have used them exclusively. One example was highlighted on a UK Land operation, where the ***use of the top drive increased the amount of abnormal drag.***

When drilling in singles with a kelly the newly drilled (30ft) of wellbore hole is wiped at every connection (without rotation).

With a top drive, drilling in stands and continuous rotation (if deemed beneficial) is now permitted, with the new hole wiped less frequently i.e. every (90ft drilled) . This resulted in quite different wellbore conditions in some formations sequences and intervals to the detriment of overall drilling performance / loss. Where after changing the frequency of wiping the hole to once every single, in such troublesome sequences, hole conditions and drilling performance (reduced loss) was much more evident.

There is a risk and caution of complacency with top drives, as they are sometimes regarded as capable of keeping pipe moving, however tight the hole or deteriorating the downhole conditions becomes. Consequently, the right and corrective actions to improve conditions are delayed or not taken at all. This is the wrong approach; top drives are good, but they are not infallible and abnormal hole drags and downhole conditions must be treated with the same amount of care as it would be if using a kelly. **Top drives are a great drilling assist but must be used wisely.**

e.g. On floating drilling rigs, the drill string compensator can play an important role in the prevention of stuck pipe by helping to control sudden movements of the pipe. When drilling, the compensator should be stroked out as far as the heave permits. This prevents the string dropping through a fast drilling break and possible becoming stuck in an unconsolidated formation. It is especially applicable for top-hole sections, where the reaction time to pick up an almost closed compensator can be too slow to save a stuck pipe incident.

If abnormal hole drag is expected when tripping out of the hole, it can be a good idea to keep the compensator unlocked. This gives the Driller more time to react if he suddenly runs a tight spot. The small amount of time gained, may make the difference between staying free and getting stuck. Be aware that come compensators' rating may not permit this.

1.3 Reducing Torque and Drag

1.3.1 Introduction

Torque and drag are caused by the frictional forces encountered between the drillstring and the borehole wall.

Torque refers to a measurement of the force required to rotate the drillstring in the borehole.

Drag refers to a measurement of the incremental force required to move the drillstring up or down in the borehole.

In extended reach and horizontal drilling, frictional forces may limit the extent of step out possible and it is therefore important to understand the causes of these forces and how they may be minimised. During well planning, torque and drag calculations will influence the possible well geometry's and step out as well as the equipment specifications required to successfully drill the well.

Excessive torque and drag can result in several problems including:

- **Twist Off's**
- **Stalling**
- **Downhole Make-Up**
- **High Break-Out Torques**
- **Stuck-Pipe**
- **High Overpulls**
- **Inability to Slide**

Although torque and drag are usually problematical features of the drilling process, they can also be used as downhole indicators of hole condition. During drilling, monitoring torque and drag is a method for optimising drilling performance and may provide indications of other potential problems such as:

- **Differential Sticking**
- **Key Seating**
- **Poor hole cleaning**
- **Hole Instability**
- **Ledging / Doglegs** *(that can then be a route to several other associated problems)*

1.3.2 Factors Which Affect Torque and Drag

The main influences on torque and drag are:

- ***The wall forces***
- ***The nature of the surfaces in contact (e.g. type and roughness)***
- ***Mud lubricity***
- ***Wellbore stability***
- ***Hole cleaning***

1.3.3 The wall forces

The wall force is effectively the force which pushes the drillstring or BHA against the wellbore. The greater this force, the higher will be the torque and drag. The influences on this are primarily the wellbore inclination and tension around doglegs.

1.3.4 Wellbore inclination

As wellbore inclination increases, more of the drillstring's weight is supported by the wellbore wall. Therefore high angle and ERD wells have higher torque and drag than vertical wells.

1.3.5 Tension around Doglegs

A drillstring under tension is pulled into doglegs as it tends to "straighten itself out". These doglegs can be either build or drop sections or unintentional tortuosity.

Some wall force may be generated by the bending of the drill pipe around curvatures. Calculations show that these forces are much smaller than the wall forces described above, even for stiff drill collars.

Drillstring weight will have some influence on wall force, particularly in horizontal wells where gravity forces the pipe onto the low side of the hole. The use of lightweight pipe will help to minimise this.

1.3.6 Surface properties

Smooth surfaces will tend to produce lower torque's than rough ones. Thus, cased hole generates less friction than open hole. There is also evidence that drilling harder sandstones leads to higher torques than when drilling softer shale formations.

1.3.7 Mud lubricity

The type of fluid present in the hole can have a significant influence on torque and drag. Oil muds are found to be more lubricating than water-based muds. Thus, oil muds are preferred for ERD wells.

It is also important to note that the concentration and type of solids in the mud can influence torque, as can the presence of lubricant additives. See the sections on "The Coefficient of Friction" and "Ways to Minimise Torque and Drag" for more detail.

1.3.8 Wellbore stability/Shale inhibition

Hole instability can be a major contributing factor to high torque and drag. Insufficient mud weight may lead to breakout/caving's which fall into the hole and pack-off. In plastic formations, such as salts and some shales, low mud weights can allow the formation to deform (creep) into the hole. In tectonically stressed areas, in situ stresses can have a similar effect, possibly leading to oval hole if the stresses are not symmetrical around the borehole.

In reactive shale sequences, mud chemistry will influence the condition of the wellbore. A water-based mud with low inhibition may allow the shale to swell, leading to tight hole and hence increased torque and drag. Poor inhibition can cause shale softening, which could have some lubricating effect, but can also make the shale more "sticky". In hard-brittle shales, insufficient shale inhibition can lead to caving's and packing off.

1.3.9 Hole cleaning

Hole cleaning efficiency has a direct influence on torque and drag. Failure to clean the hole properly will allow cuttings beds to build, interfering with pipe rotation and movement of the pipe in and out of the hole. In some ERD wells, torque has been used to monitor hole cleaning efficiency.

There is some laboratory evidence suggesting that cuttings beds can improve lubricity and reduce torque, by providing a lubricating bed for the drillpipe. However, the potential adverse effects (pipe sticking, large overpulls etc.) outweigh any benefit.

1.3.10 Predicting and Monitoring Torque/Drag

1.3.10.1 *The Coefficient of Friction*

The coefficient of friction (u) provides a useful measure of the friction between two moving surfaces. Values for u are used in predictive models (e.g. the Drillstring Simulator - see below) to estimate likely torque and drag figures.

The coefficient of friction is the ratio between the applied (sliding) force, F, and the normal force, N, between two surfaces in contact i.e. u = F/N

In drilling, N is effectively the wall force (see previous section) and F is the torque or drag. A simple case would be a tool joint resting on the borehole wall in a horizontal well; the normal force would be the weight of the drill string, and the applied force would be the torque required to turn it. The coefficient of friction is independent of contact area and velocity but depends upon surface type (including roughness) and the nature of any fluid between the surfaces.

Some important facts relating to u are:

- **A low value of u is best** - the lower the value of u, the lower the torque and drag.
- **Mud lubricity** - Oil based mud gives lower values of u than water-based mud.
- **Cased/Open Hole** - Cased hole generates less friction (lower u) than open hole.
- **Formation Type** - In general, drilling harder sandstones leads to higher coefficients of friction than drilling softer shale formations.

"DEFAULT" COEFFICIENT OF FRICTION VALUES

Mud Type =	OBM	WBM
Cased Hole	0.17	0.24
Uncased Hole	0.21	0.29

1.3.10.2 *The Drill String Simulator*

Proper analysis of the interactions downhole requires the use of a torque and drag simulation model. Companies and operators provide their own dedicated torque/drag models and Drill String Simulator (DSS). Well data can be input and a drillstring analysed.

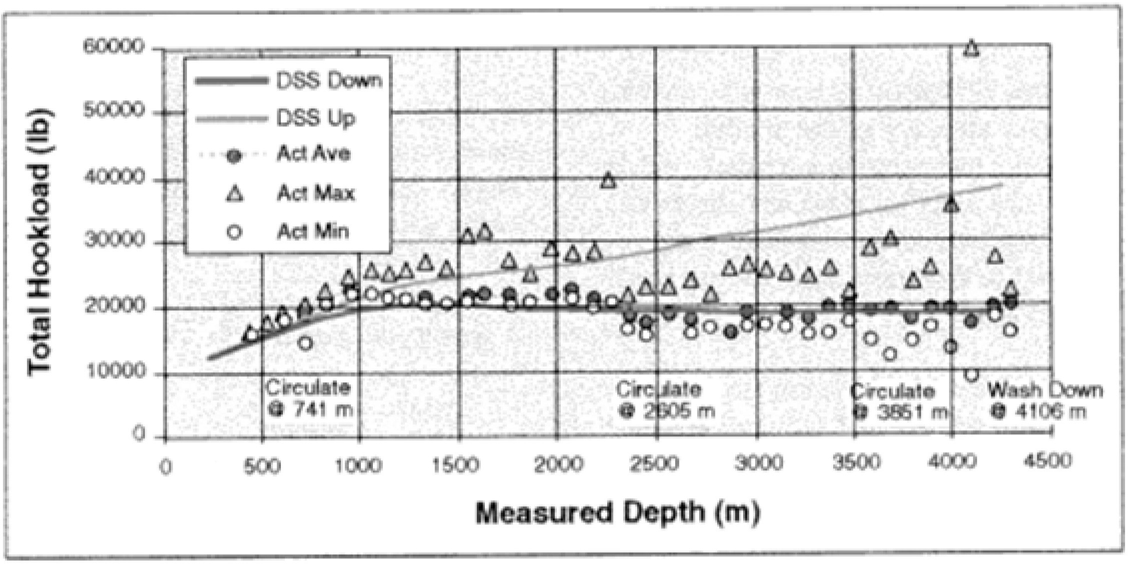
Note that torque and drag analysis is not limited to drill strings but can be conducted for all strings in the wellbore.

As an example one could conducted drag simulations for running the 9 5/8" casing on an extended reach well. Divergence from prediction may provide a valuable early warning indicator of running problems until hook loads return to predicted.

Some Drilling Operations have implemented procedures to record the following data at the rig site at every connection:

1. **Rotating Weight** - off bottom with normal circulation
2. **Torque Off Bottom** - with normal circulation
3. **Pick-Up Weight** - with no rotation but normal circulation
4. **Slack-Off Weight** - with no rotation but normal circulation
5. **Torque on Bottom** - with normal WOB and normal circulation

These values are recorded in the drillers handover notes to ensure that the knowledge gained is passed over between crews.



WYTCH FARM 1F-20 95/8" CASING DRAG

1.3.11 Ways to Minimise Torque and Drag

1.3.11.1 *Well profile design*

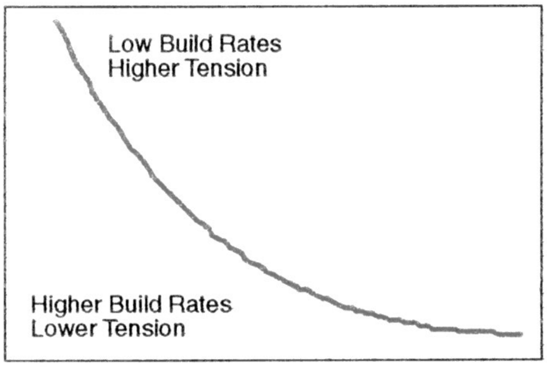
Well profile design to minimise torque and drag involves minimising wall forces. Since string tension is always highest at surface (which can lead to high wall forces as described above), the way to minimise wall forces is to minimise doglegs (build rates) at surface, and to build angle towards the target further downhole where string tension will be less. This is achieved by drilling the well with a tangent angle as close to the critical sliding angle as possible, causing the string to "glide" under its own weight.

Well profile design is also a compromise meeting a large variety of requirements, of which torque and drag minimisation is just one factor. For conventional wells (low reach/TVD ration), "under-section" profiles (which have a deep KOP) are better because they give tangent angles closer to the critical sliding angle. In contrast, the "build and hold" profile causes higher tension, hence torque and drag. In ERD wells however (high reach/TVD ration), a high kick off point will be required to provide the critical sliding angle in the tangent section.

Note that in deep wells, it is particularly important to drill the top sections as smoothly as possible to minimise the torque contribution from tortuosity. Excessive use of steerable assemblies can worsen tortuosity, rotary assemblies are beneficial.

1.3.11.2 *Drillstring design*

Torque and drag can be minimised by optimising drillstring design. By using the smallest and lightest weight drillpipe weight and tension is minimise. Tapered drill strings are particularly effective where stronger 65/8" or 5½" drillpipe is only used at the top of the string where loads are lightest.



THE IDEAL PROFILE

1.3.11.3 *BHA design*

BHA's have historically been designed to ensure that WOB can be applied to the bit without putting drillpipe into compression. Experience with horizontal wells where compressive forces in drillpipe cannot be avoided have shown these assumptions to be overly conservative. BHA's should be designed for directional control and of minimal weight in ERD wells. A torque and drag program (such as DSS) would be used to analyse the probability and consequences of buckling.

1.3.11.4 *Mud design*

As noted earlier, mud type can have a significant influence on torque and drag. To minimise torque and drag, muds should be designed to satisfy the requirements of wellbore stability, hole cleaning and lubricity. Wellbore stability and hole cleaning are covered elsewhere in this manual (in the shale problems section, wellbore stability section and hole cleaning section). Here we only consider mud lubricity.

Mud lubricity can be assessed in the laboratory with testing devices which crudely attempt to simulate field conditions. The resulting friction coefficients possess a degree of error. However, they indicate trends and so are a useful way of screening lubricant additives and comparing mud systems. The trends are most useful when correlated with data from actual wells.

1.3.11.5 *Water based muds*

The coefficient of friction will depend on the formation type being drilled. For water-based muds where shale softening is possible due to poor inhibition, decreased values of friction may be observed. In hard sandstone etc. higher values of friction may be observed for an identical mud system.

Baryte improves lubricity when used in weighted systems possibly due to the formation of a soft "bearing layer" modifying the surface contacts. Above ca. 1.2 to 1.3sg baryte promotes reduced coefficients of friction.

Polymers in water-based muds can have a beneficial effect on lubricity - partially hydrolysed polyacrylamide (PHPA) can exhibit a friction reducing effect.

The coefficient of friction is less for a steel/steel contact than a steel/rock contact (cased hole has a lower coefficient of friction than open hole.

A wide variety of lubricants are available for addition to water-based mud systems. These have been systematically evaluated within BP and all show different performance features in reducing the coefficient of friction. They are of benefit in low mud weight systems but less benefit in high mud weight.

1.3.11.6 *Oil based muds*

In the laboratory and in the field, oil-based mud systems exhibit lower values of friction than water-based mud systems. By virtue of its film forming capacity, oil is intrinsically a better lubricant than water, however, the presence of strong surfactant packages in an oil-based mud system may also aid the lubricity effect.

The positive effect of baryte is less pronounced for oil-based muds but oil/water ratio does noticeably affect lubricity: lubricity decreases as the water content of the oil mud is increased.

The coefficient of friction value measured in laboratory tests is comparable for metal-metal and metal-sandstone contact. As with water-based mud, it is still observed that cased hole has a lower coefficient of friction than open hole.

Some of the new synthetic oil mud systems demonstrate better lubricity than those formulated with mineral oil.

So far, lubricants in oil-based mud have had little application, as OBM's are considered sufficiently lubricating. Water based mud lubricants are not effective in OBM. Solid lubricants (graphite powder and lubra beads (see below) are more effective.

1.3.12 Physical Methods

1.3.12.1 *Lubricating Beads*

A commercially available product called Lubra beads (small glass spheres which function like ball bearings) has been trialled with some success resulting in torque reductions of up to 20%. Removal of the beads by cuttings handling equipment can be a problem. To get around this, the product can be used selectively to spot areas where high torque is occurring.

1.3.12.2 *Drillpipe Coatings*

A small amount of work has been carried out looking at coatings which could be applied to steel to reduce the steel/steel friction coefficient. Hard banding of tool joints to reduce casing wear has also been examined. Because of the extreme forces involved in drilling, the integrity of the coating remains an issue.

1.3.12.3 *Drillpipe Protectors*

Non-rotating drill pipe protectors (DPP's) have been shown to reduce torque by up to 30% in many Extended Reach 'ERD' wells, The recommended tool at the moment is the Wester Well Tool non-rotating stabiliser, although other tools are being developed. However, there are several downsides to their use:

- annular pressure loss is increased (up to 2 psi per tool, quoted)
- sliding ability is reduced
- durability still causes some problems
- their use is restricted to cased hole
- significant cost and installation/removal time

Their use should, therefore, be optimised by placing them in areas of highest wall force. Wall force should be calculated using a drillstring simulator to determine optimum placement and the number per joint required.

1.3.12.4 *Bearing Subs*

Bearing subs can and have may be used in open hole where DPP's are not suitable. Again, sliding may be hindered in exceedingly high angle wells. Time for make- up and cost, must be considered.

1.4 Differential sticking

1.4.1 Planning Stage

Check in the section the presence of any permeable formations which may lead to differential sticking. In this case the Chalk or sands could be a problem area.

Estimate the pressure of the problem formation. ***Check with Mud loggers***. If the risk of differential sticking is thought to be high, make this clear by communicating this to each other.

Thick reservoirs can give a high risk of sticking, because of the low formation fluid density.
NOTE: Overbalance can rapidly increase with depth when drilling through a gas reservoir.

Where differential pressures are thought to be high across a permeable formation, consider taking a formation pressure tool measurement. The risk of getting the logging tool stuck should be considered, but this may be outweighed by the value of the information on later wells. The formation pressure test tools data collected is useful to a Drilling, Petroleum, Reservoir, Pressure management and Geomechanics Engineer.

If differential pressures are known to be high, give careful thought to the logging programme, particularly the number of pad tools. These are always susceptible to becoming stuck and especially those tools with radioactive sources should be used with discretion.

Stuck pipe freeing materials should be available at the rig site. Sufficient volume to spot a pill covering the BHA, plus 50barrels, is the recommended inventory, although this should be greater for remote sites.

1.4.2 Rig Site Precautions

Continuously track the differential pressure across permeable formations, as accurately as possible. Follow the trends of the D exponent graph, trip gas levels and connection gas levels, which should indicate changing pressures.

Keep the mud weight at the lowest safe level. A widely used rule of thumb is 200 psi static overbalance, although conditions will frequently dictate a different figure. Aim to keep differential pressures across permeable formations to a minimum.

Maintain a tough, thin filter cake and keep drilled solids content to a minimum.

Always keep the drillstring moving where reciprocating is the preferred motion, as it shows that the pipe is free to trip in and out of the wellbore freely. However, when this is not possible, *E.g. On connections,* rotation is considerably better than leaving the pipe static.

Do not programme unnecessary surveys as they are a ***high-risk*** operation. An MWD surveying tool is less likely to become stuck than a single shot because the string is stationary for a shorter time. In a ***high-risk*** area, this alone may justify the additional cost of an MWD.

Differential sticking regularly occurs during a well kill procedure, due to the increased mud weight. Under no circumstances should the fear of becoming stuck dictate the kill weight to be used. However, excessive safety margins are sometimes used in both kill mud weight and circulating pressures. These increase the chance of stuck pipe.

1.5 Inadequate cleaning

Poor hole cleaning will cause wellbore conditions to steadily deteriorate, rather than having an immediate effect. Consequently, ***there should be ample warn signs and opportunity to recognise and react to each specific problem.***

1.5.1 Rig Site Precautions

Prior to starting a trip, the hole should be circulated until it is as clean as is practically possible. A minimum circulating time should be predetermined, but a trip should not be started if there are still significant quantities of cuttings coming over the shakers at that time. It may be beneficial to rotate and reciprocate the string while circulating in inclined wells, as the movement assists hole cleaning by disturbing cuttings beds.

There are situations where circulation alone could be maintained for days without the hole being effectively completely cleaned. This may often be the case with cuttings beds or wells with severe over gauged sections. Special tripping procedures may need to be used for this type of well.

- *Do not permit the flow rate to drop below the minimum required to clean the hole.*
- *If a mud pump goes down, stop drilling until it is repaired.*
- *Trip back into the shoe if the delay is going to take a long period of time.*
- *Do not drill ahead, expecting to clean the hole at a later stage. It may be too late.*

There are several indicators which can identify hole cleaning problems:

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

These must be recognised, and corrective actions quickly taken (who, when, what/how).

Minimise the amount of over gauged hole, where annular flow rates are reduced, and cuttings build up is most likely to occur. Serious problems may result in the next wellbore section if a large casing sump is drilled. Always keep the sump to a minimum. Big safety margins are unnecessary.

Other avoidable causes of over gauging hole are:

- ***Excessively high flow rates and jet nozzle velocity (Wash-outs)***
- ***Inadequate mud weight e.g. Cave-ins.***
- ***Incorrect mud formulations e.g. soluble formations.***

Control ROP to a level at which the cuttings can be safely removed ***first form the bit*** and then from the well. This must be applied to instantaneous ROP, not average ROP.

Always look at the shakers to get a feel for the effectiveness of the hole cleaning. Does the volume of cuttings seem right for the ROP? Do slugs of cuttings appear followed by very few cuttings? The shakers will give an early indication of a hole cleaning problem.

When a downhole motor is being used in an inclined well, without rotating the drill string, it is probable that the cuttings beds are not being disturbed. If possible, rotate the string prior to tripping out of the hole.

1.6 Formation instability

1.6.1 Rig Site Precautions

Unstable formations can give a variety of combinations of the following. Recognise them and respond to them:

- Drag on Trips
- Fill on taps
- Excessive material on the shakers
- Excessive torque
- Increasing MBT levels which are not due to mud treatments
- Salinity changes in the water phase of oil muds
- Out of gauge hole
- Cuttings from an earlier drilled section

Mud properties must be maintained, particularly in shales. Even if it means tripping back to the shoe, time spent conditioning mud may to prevent vs cure a stuck pipe incident is often merited..

Trip with caution through swelling clay/shale formations.

Wipe, wash and/or Ream each single if *abnormal drag is observed when picking up off bottom, on connections etc?* when wiping string prior to making a connection. When using a top drive, stop rotating, pick up midway through each stand and ream down is what we advocate as best practice.

Only if hole conditions are severe, more frequent reaming is the required. Time spent improving conditions is not time wasted. *Backream as a last resort is the evident view.*

A top drive allows tight sections to be tripped through using slow rotation and circulation. After pulling into a tight spot, run back into gauge hole and circulate before back reaming out.

Tight hole depths must be logged by the Drillers/Tool pushers.

Drillers should be on the brake when tripping through problem formations, as they will have gained a feel for the hole.

At the first indications of tight hole, the Driller should inform Drilling Representative and the Toolpusher.

Wiper trips should be conducted regularly according to predetermined procedures, with additional trips being made if required.

In tight hole situations, consideration of the stuck pipe risk should be made before dropping a single shot survey.

Never spend unnecessary time in open hole.

Backream as a last resort is the evident view.

- In an unstable situation this is generally more of hinderance than a help/assist.

1.7 Bottom hole assembly changes

1.7.1 Rig Site Precautions

Always gauge bits and stabilisers before and after each trip. Ensure that the correct gauge ring is used for bits, some PDC bits need special rings.

Unless torque records clearly show the point at which the bit gauge became worn, consider reaming the whole of the section drilled by the bit.

When running a BHA of increased stiffness, expect to have to ream. Do not trip into the open hole rapidly.

If the hole is thought to be under gauged, extreme caution must be applied when tripping into the hole.

1.8 Stuck pipe planning prevention

Before planning the well, all persons involved in the process should collect relevant prevention data from the offset wells. *i.e. a well drilled in the close vicinity and/or analogous to intended well(s).* These wells offer a wealth of information that can be used for correlation with the current planning and execution of the new well.

1.8.1 Data from offset wells

For that purpose, the following should be noted:

- Drilling reports from offset wells (which may contain much of the other information listed below).
- Details of any formation stress tests including LOT's and FIT's.
- Daily mud properties, mud losses encountered.
- Details of any pipe "sticking" and/or excess reaming, backreaming.
- Composite logs, dip meter or borehole geometry logs, any calliper logs, density logs and sonic logs.
- Description of any major faulting in the region (normal, stick-slip, etc.).
- Details of permeable, unconsolidated formations and salt zones. The depth and thickness of these sticky formations should be noted along with the mud properties used.
- Record of key seating along with associated dogleg severity and ROP through the section.
- Formations that caused circulation problems and the mud weights used.
- Record of any wellbore deterioration and/or associated solutions.
- ***Backreaming!*** Try and ascertain why this was evidently so?

1.8.2 During well Planning

When planning in addition of the data provided by offset wells, the following should be applied.

- Identification of the potential troublesome formations and any special procedures adopted through these zones.
- A top drive can be beneficial is used correctly in known sticking areas aiding to reduce tight holes problems lost time and waste that can result. *i.e. laying down and picking up single vs stands on kelly rig*
- Careful BHA design with special attention to keeping the BHA length as short as possible (run only what is needed)
- The number of collars and particularly large OD (outside diameter) of the BHA collars should be kept to a minimum or fully risked and justified.
- Careful mud design and planned mud weight help to keep the hole in optimum condition.
- A hydraulic program should be run for the planned BHA and hole sizes.
- Optimal mud conditioning is critical to maintaining an in-gauge wellbore condition. Careful consideration of the mud system, solids control and the right mud weight will be rewarded through subsequent trouble-free drilling, tripping, casing and cementing operations.
- Choose properly the depth for setting casing according to formations or problems experienced. *E.g. to case off troublesome formations.*
- Assure drilling contractor are key 3rd party personnel understand and are compliant with the operators/ contractor's tight hole and stuck pipe procedures as outlined.

1.8.3 Rig operating guidelines

Some useful practices to prevent stuck pipe:

- At first indication of tight hole or stuck pipe warning signs, the Company representative and senior drilling contractor persons must be called to the drill floor.
- In tight wellbore **be patient**. Never force the string through a tight spot and apply overpull incrementally in stages to best assess downhole condition. Always assure the pipe can be worked in the opposite direction before increasing limits being applied.
- Time spent conditioning mud is often rewarded. Circulating sooner rather than later during drilling or tripping will also likely prevent wellbore deteriorating further.
- Always assure Drillers and Supervisors are aware for what to "**immediately initiate"** for specific stuck pipe mechanisms and events.
- Assure that the drill string is always kept moving barring when making connections or surveys in open and/or deviated wellbores.
- Forcing the string through a tight spot may lead to the string becoming stuck.
- Assure personnel know how Jars and accelerators are expected to work.
- Avoid complacent use when operating with a top drive. Different formations and variant wellbore profiles, sizes, require best practices drilling techniques irrespective of drive system being used. *E.g. Notably backreaming should be only*

applied when deemed required to serve a specific purpose and not as a matter of course.

- Minimize the time spent in the open hole will reduce stuck pipe. Any rig repair should be done with the drillstring inside the casing.
- Wiper trips should be made according to predetermined procedures and only as/if wellbore conditions dictates.
- Always have someone monitor returns and at shakers during drilling and circulating the wellbore. Deviations to be reported to the driller, mud engineer and company representatives immediately.
- Clean the open hole prior to tripping out of it. Note: On subsea wells this does not necessarily mean circulating bottoms up where staying on bottom may be more detrimental to the wellbore than getting back to the shoe and then circulating the complete well clean.
- On floating rigs, the motion compensator should be well maintained to prevent sudden movements of the drill string.
- Always exercise caution when tripping in open hole, particularly during the first several stands where the Company representative and a senior drilling contractor person must be in attendance on the drill floor.
- Always be prepared to wash and/or ream the last few joints back to bottom.
- There are several measurements which can be monitored by the drilling team to avoid stuck pipe. It is the responsibility of all personnel to identify and confirm a sticking condition and/or the warning signs.
  - They must be able to communicate in a clear and simple way.

1.8.4 Immediate actions & Primary Sticking Measurement

Immediate actions should be discussed so the driller knows immediately what to do in three key instances as per examples guidelines provided i.e.

1. **Hole Instability (pack-off).**
2. **Mechanically stuck**
3. **Differentially stuck.**

Freeing techniques are described in a separate section within this document. However in this process discussing and agreeing on key drilling parameters such as over pull and torque limitation are vital to staying stuck free from within the wellbore.

OVERPULL: Over pull is a primary measurement of sticking. It is the maximum tensile strength allowable on the weakest joint of drill pipe. It means that if the force necessary to free the drill string exceeds this force, the string is ***STUCK***

TORQUE: Torque is a primary measure of sticking. It increases gradually with depth.

A rapid trend or sudden increase in torque can mean a severe dogleg or abnormal sticking forces on the BHA, but don't forget that it can mean other down-hole status such as changes in formation, increase in weight or a cone locking.

1.9 Stuck Pipe summary guidelines

Stuck pipe is therefore a matter of appreciating the danger of incorrect mud weights inferior quality mud and an insistence for compliance to recognised standard Oil field practices.

1. When stuck pipe cannot be freed, establish as soon as possible the stuck point.

Prevention is always far cheaper than the cure and for whatever tool goes down the wellbore: i.e. contractor or rental tools ensure these have a certificate of their last inspection. Finally, negligence and payment disputes are solved much more readily if regular inspection and reports are available, assurance systems are therefore required to prevent such disputes.

1.9.1 Stuck pipe prevention flowcharts

It is strongly recommended that a selection of identification decision trees flow charts based on operations conducted should be developed for each drilling, workover program.

1.10 Mud properties quick reference

1.10.1 Oil Based Mud - Engineering Comments

- Oil mud salinity must be at least as high as the pore fluid salinity of the shale.
    - This prevents water entering the shale by osmosis.
- When drilling salt formations, OBM salinity should be high
    - *e.g. 300,000 mg/l chloride,* to minimise salt dissolution into the water phase of the mud.
- Synthetic oil muds (pseudo oil muds) should be considered where environmental constraints restrict the use of conventional oil.
    - Shale inhibition is equally effective in these systems.
- In micro-fractured shales, use an exceptionally low fluid loss mud (HTHP< 3mls) and add fracture sealing additives.
- Always consult specific operators or 3rd party company mud specialists as systems vary widely in rheological properties, temperature stability and cost per barrel.
- Oil based muds often allow a lower mud weight to be used to prevent collapse in shales. This provides a larger mud weight window.
- An oil-based mud properties quick reference guide is provided in the table below.

Table 1: Oil Based Mud Properties – Quick Reference

TEST PROPERTY	UNITS	RELEVANCE TO MUD SYSTEM	NORMAL RANGE	DANGER SIGNS
PV	cP	solids concentration	as low as possible	Rapid increase with little change in mud density: differential sticking
YP	lb/ 1000ft 2	solids carrying capacity	increase with hole dia.	Variation from mud specifications Too low: poor hole cleaning
Gels	lb/ 100ft 2	suspension qualities of mud when stationary	minimum 3/6	1 High progressive gels 2 Gels too low: cuttings settling
Emulsion stability	volts	mud stability	400V+	Low values mean mud may break down
HPHT fluid loss	cc	filtration characteristic	below 5 cc	1 Water in filtrate: mud stability 2 Increasing fluid loss: differential sticking
Lime	ppb	excess lime content	3 - 5lb/bbl	Decrease below mud specification could affect stability
Chlorides	mg/l	water phase salinity	180,000-275,000	Variation from mud specification may give shale problems
OWR	ratio	oil/water content of mud	50: 50 - 90:10	Decrease: water contamination may affect stability of mud

1.10.2 Water Based Mud - Engineering Comments

- If water-based mud is to be used, carry out a screening programme at an early stage to allow optimisation and discuss issues with operator's fluids specialists and the mud companies.
- Water based muds are less lubricating than oil muds, therefore expect higher torque in high angle wells. It may be necessary to add lubricants to the system.
- In salt sections, it is important to match the fluid to the type of salt. Salt saturated muds (NaCl) are used for simple halite's; mixed salt systems are available for complex salts such as Carnallite. Obtain specialist advice on these.
- Use a low fluid loss mud (e.g. API < 5ml, HTHP (250°F) <14ml) in micro-fractured shales and add fracture sealing additives
- A water-based mud properties quick reference guide is provided in the table below.

Table 2: Water Based Mud properties - Quick Reference

Test Properties	Units	Relevence of mud system	Normal range	Danger signs
PV	cP	solids concentration	varies with density	Rapid increase with little change in mud density: differential sticking
YP	lb/1000ft 2	solids carrying capacity	increase with hole dia.	Variation from mud specifications Too low: poor hole cleaning
Gels	lb/100ft 2	suspension qualities of mud when stationary	minimum 3/6	1 High progressive gels 2 Gels too low: cuttings settling
Inhibitor conc.	varies	stabilise formation/ prevent shale hydration	varies	Variation from mud specification Too low: mud chemistry problems
API fluid loss	cc	filtration characteristic	5 - 8 cc	Too high: excess fluid loss (differential sticking)
MBT	ppb	level of bentonite equivalent solids in polymer muds	below 20ppb	High non-inhibited clay may give viscosity problems and thick filter cake
Chlorides	mg/l	osmotic balance of mud with formation salinity	20 - 80K 180K s.sat	Variation from specification Too low in salt muds: hole washouts
Total hardness	mg/l	Conc Ca & Mg ions in mud	below 200 mg/l	High levels may reduce yield of bentonite and polymers

1.11 Communication

1.11.1 Meetings

Regular meetings are a vital tool in the maintenance of the team spirit and provide a vehicle for two-way communication.

It will be necessary to determine what is appropriate for each locality, but the following meetings are suggested.

- Well specific training and action plan creation.
- Pre-spud
- Pre-section or pre drill-out.
- Pre-job (*major phase jobs like cementing, testing etc*.).
- Pre-formation (*before drilling into a troublesome formation*).
- Pre-tour.

  Note: There should be full involvement from the office-based staff.

There must be a clear statement of who is responsible for organising and leading each meeting.

This will again depend on the location, but consider offering the designated Rig-site Champions, Drilling Supervisor and other senior staff some facilitation training if possible.

Questions for planning a successful meeting

- What persons are attending?
- What is the clear agenda?
- How is the room set up? Is this set-up satisfactory?
- Is there enough time?
- How will information, actions etc., be recorded?
- What important instructions have been transferred onto the crews?
- How are the attendee's comments recorded?
- What follow up corrective actions have been identified?
- Who should receive a copy of the minutes?

1.11.2 Handovers

Most stuck pipe incidents result within two hours of the Driller's or crew shift change. This is due in part to inadequate briefing of their relief.

Stagger handovers so that there is sufficient overlap between Tool pushers, Tour Pushers, Drillers, Assistant Drillers and Mud Loggers. Allow some to work 12 until 12, and others 6 until 6 or 9 until 9 which will improve continuity.

Consider the use of pre-printed handover forms that help to give the personnel coming on shift a much better idea of the way the hole has been behaving. Examples of a Driller's and a Shaker hand's handover forms are shown in the appendix. These are only examples and it may be best for each crew to design their own so that it is most relevant for their rig and their operation. It is everyone's responsibility to ensure they have given or received a comprehensive handover.

1.11.3 Reporting

To learn from every incident a *Stuck Pipe Incident Report Form* should be completed. An example is illustrated in figure 10 however it may be best to develop one that best fits local circumstances and conditions.

The responsibility for filling in the report form will differ from rig to rig. In some places it will be the Driller, others the Drilling Supervisor or Engineer and so on. It is essential that the chain must be established in advance so that it is clear who must fill out the form, who needs to be copied on it and who is responsible for follow-up actions.

The value of a well filled out report can be seen by searching these forms within the captured Knowledge Base. This provides a power full engineering tool. For every stuck pipe incident, a report form should be sent to the rig's Drilling Superintendent with specific corrective actions captured within the form, daily drilling reports and/or lessons learned data list, base or software system used.

1.12 Stuck pipe reporting

A crucial part of stuck pipe prevention is recording information which can be shared or passed on to the next shift. Recording stuck pipe incidents makes it easier to learn from past events and share the lessons learned with others. The forms in this section are ideas which the rig will find useful. The best forms are designed by their users so feel free to alter any of them, so they suit you better.

1.12.1 Stuck Pipe/Tight Pipe Incident Reporting Form

This is designed to help the driller identify the stuck pipe or tight-hole mechanism and select the best remedial action. The evaluation should help the rig team understand what caused the problem, the warning signs, and how it can be avoided in the future.

Figure 1: Illustrative Stuck pipe incident reporting form.

STUCK PIPE/TIGHT PIPE INCIDENT REPORTING FORM

WELL NAME		WELL TYPE		SPUD DATE		DIRECTIONAL PROFILE
RIG NAME		RIG TYPE		DRL CONT.		

STICKING INCIDENT:

Date	Time	MD of Well	Depth of Bit	Stuck Point	Hole Size
Hole Angle	Mud Weight	Mud Type	Flowrate	Overbalance	Formation

BOTTOM HOLE ASSEMBLY:

TIME SINCE CREW CHANGE:

Drl. Supv.	Toolpusher	Driller	Dir. Drl.	Mud Eng.	Mud Log.	Rigsite DE

OPERATION INSTANT HOLE GOT TIGHT/PIPE STUCK:

SUSPECTED CAUSES:

☐ Differential Sticking	☐ Key Sealing	☐ Reactive Formation	☐ Frac/Faulted Formation	☐ Mobile Formation	☐ Unconsol. Formation	☐ Geopressured Formation
☐ Junk	☐ Well Geometry	☐ Hole Cleaning	☐ U/Gauge Hole	☐ Green Cement	☐ Cement Blocks	☐ Collapsed Casing

WARNING SIGNALS:

	YES	NO	REMARKS
Size/Amount of Cuttings over Shakers:	☐	☐	....
Previous Tight Connections:	☐	☐	....
Increased Torque:	☐	☐	....
Increased Drag:	☐	☐	....
Mud Losses:	☐	☐	....
Change in Formations:	☐	☐	....
Change in Pump Pressure:	☐	☐	....
Change in Mud Properties:	☐	☐	....
Change in Formation Pressure:	☐	☐	....

LOST TIME (HRS):	**L.I.H. COST ($):**
LOST TIME COST ($):	**TOTAL COST ($):**

Table 3: Stuck pipe incident reporting form

ACTIONS TAKEN BEFORE STICKING INCIDENT:
ACTIONS TAKEN AFTER PIPE BECAME STUCK:
HOW COULD THIS STUCK PIPE INCIDENT HAVE BEEN PREVENTED:
PLANNED ACTION TO BE TAKEN/RECOMMENDATIONS:
WHAT PRECAUTIONS CAN THE STUCK PIPE TEAM TAKE TO PREVENT A RECURRENCE:
HOW CAN THE LESSONS LEARNED FROM THIS INCIDENT BEST BE TRANSFERRED TO OTHER AREAS:

1.12.2 Drillers Handover Form

Most stuck pipe incidents occur within two hours of the driller's shift change. This is due to the drillers (and other crew members) not briefing their relief properly. If you think handovers could be improved, consider using a handover form. This would give the driller coming on shift a far better idea of hole condition and what problems he may encounter.

Figure 2: Example Drillers Handover Form

HANDOVER TIME

Date | Time | Depth | Mud Weight

HOLE STATUS AND PRECAUTIONS

Formations open
Formations coming up

DRILLING TRENDS

Mud weight	On bottom torque
Pick up weight	Off bottom torque
Slack off weight	Mud solids content
Rotating weight	Mud gels
Pore pressure	

LAST TRIP

Depth | Condition

NEXT TRIP

Depth | Maximum allowed overpull

SHAKERS	**EQUIPMENT PROBLEMS**
Cuttings volume changes Cuttings size/shape	

WARNING SIGNS/SPECIAL INSTRUCTIONS

1.12.3 Shaker Trend Sheet

The returns can tell a great deal about hole condition. Keeping a record of the returns may help identify hole problems early. Such a record could be kept by the shaker hand or the mud loggers.

Figure 3: Example Shaker Cuttings Description Sheet

SHAKER CUTTINGS DESCRIPTION TREND SHEET

WELL NO. DATE

DEPTH	TIME	CUTTINGS DESCRIPTION	CUTTINGS VOLUME Increase/decrease	CUTTINGS SIZE Inches	MUD WT In/Out	COMMENT

1.13 Rig stuck pipe assessment

1.13.1 Rig site visit plan, introduction

1.13.1.1 *Objectives*

1. To obtain an assessment of the current Stuck Pipe exposure within the organisation.
2. To assess the awareness towards stuck pipe in the offshore team.
3. To recommend onshore / offshore drilling team stuck pipe requirements.
4. For the stuck pipe report to generate actions and recommendations from the answers provided by questionnaire.
5. To input to update or upgrade the level of stuck pipe training.

1.13.1.2 *Expected Outcomes*

1. Onshore support team to increase the stuck pipe awareness offshore.
2. Alert onshore support team of action(s) that need to be taken to prevent the occurrence of a stuck pipe incident.
3. For stuck pipe to become a regular offshore awareness culture.
4. Courses set up as necessary.
5. Well programmes screened for stuck pipe prevention.

1.13.1.3 *Actions*

1. Stuck Pipe Rig Visits
2. Stuck pipe culture supported by the onshore superintendent / offshore Co Rep / Rig Supt
3. Regular interaction with well specialists via the rig stuck pipe champion.
4. Use of stuck pipe awareness material: Videos, Modular Training, hole section discussions.

1.13.2 **Rig details**

Date of Visit	
Drilling Contractor	
Name of Rig	
Type	
BP Co Rep	
Rig Superintendent	
Country	
Field	
Well	
Off / Onshore	
Operations at time of visit	
Visit conducted by:	

1.13.3 General Stuck pipe awareness

1. Have all drilling crews been on a stuck pipe course?	
2. Is stuck pipe mentioned on the Rig Training Matrix?	
3. When did they attend the course?	
4. Have the crews attended other drilling training courses?	
5. Does the rig have a stuck pipe awareness campaign onsite/onboard?	
6. Are there any stuck pipe posters displayed on the rig in English or other language?	
7. Are the stuck pipe posters up to date?	
8. In what locations are the posters displayed?	
9. Who on the rig champions stuck pipe?	
10. How often is the drillpipe laid down and inspected?	
11. How often are the DC's and HWDP inspected?	
12. What is drilling tubular failure rate?	
13. Are down-hole equipment manuals supplied to the rig?	
14. Does the Rig Superintendent (TP) have a well programme?	
15. Is there a well programme wall chart in the Rig Superintendent's (TP) office?	
16. Is there a mud pump fluid end preventative maintenance procedure?	
17. Does the rig lose time due to pump failure	
18. Other	

1.13.3.1 *Awareness Material*

1. Are the crews aware of any stuck pipe campaigns?	
2. Are the stuck pipe loss figures prominently displayed?	
3. Does the rig have any stuck pipe awareness material?	
4. What awareness material is presently used on the rig?	
5. Are the rig team aware of the stuck pipe knowledge base available on the Intranet?	
6. Do they access the Knowledge Base?	
7. How many copies of the Rig-site Modular Training Folders are on the rig?	
8. How often is the Rig-site Modular Training Folder used by the crews?	
9. How often do the crews watch and then discuss the training videos related to hole cleaning?	
10. Is this recorded anywhere (IADC)?	
11. Are the stuck briefs recorded?	
12. Other	

1.13.3.2 *Rig floor management*

1. Is stuck pipe discussed by crews @ toolbox talks? How often?	
2. Are stuck pipe incident avoidance discussed with the drilling team?	
3. Is the stuck pipe poster displayed on the rig floor? Is the poster theme discussed?	
4. Is stuck pipe discussed @ pre-hole section team brief?	
5. Hole section wall chart for the well, on the rig floor?	
6. Is the hole section chart displayed in the drilling contractor's office?	
7. Are there written and current instructions from the rep or TP on the rig floor?	
8. Is there a lithological column provided and displayed on the rig floor in prominent view for the driller?	
9. Is there a written stuck pipe procedure on the rig floor showing the working parameters of the BHA *i.e.: max o'pull, torque limits of the drillstring in use?*	
10. Is the driller or the assistant driller aware of his working stuck pipe parameters in the event of becoming stuck?	
11. Is there a clear pipe tally on the rig floor?	
12. Are all the present drilling parameters visibly recorded?	
13. Does the driller record information on a trend sheet?	
14. Does the drillers handover stuck pipe pro-forma?	
15. Is tight hole mentioned in any form?	
16. Does rig rep/ tool-pusher stand by on the rig floor during open hole operations including running casing?	
17. Is the directional driller present on the rig floor during assembly make up?	
18. Is there a fishing inventory? Does it cover all the tubulars, BHA assembly and all the down-hole tools held on the rig?	
19. Do you stage circulate on tripping in or tripping out?	
20. Do you minute your toolbox talks?	
21. Other	

1.13.3.3 *Directional drillers*

1. Which stuck pipe course and when did they attend?	
2. Is there a clear bottom hole assembly on the rig floor?	
3. By whom is the bottom hole assembly sheet prepared?	
4. Are all the dimensions of the BHA well recorded?	
5. Detailed drawings of the BHA elements drawn?	
6. Minimum BHA's run with respect to the max WOB reqd.	
7. Satisfied with the BHA design run on well?	
8. Are there stabiliser callipers and ring gauges available to cover all blade sizes?	
9. Are there ID and OD callipers on the rig?	
10. Are there bit gauges to cover all used sizes?	
11. Satisfied with the quality of stabilisers that are supplied?	
12. Are the string stabilisers supplied according to the specification that is requested?	
13. Are they over-gauge, in gauge or under-gauge to what you request?	
14. Other	
14. Does the shape/length of the string stabiliser blade satisfy the requirement for drilling is this area?	
15. Do the stabilisers on the motors meet the specification you request?	
16. What improvements could you suggest optimising the performance of BHA's and ROP?	
17. Do you include a dart sub in the BHA and does the dart have a fish-neck?	
18. Is the dart kept on the rig floor in an oil bath?	
19. Is the dart placed in the most optimum position in the BHA with respect to stuck pipe and fishing?	
20. Will the dart pass through all the BHA components above the dart sub. Jars etc?	
21. Will the string-shot pass through the dart sub?	
22. How often do you routinely change out the jars?	
23. Do you run tandem jars? In the BHA and in the DP?	
24. Do you run accelerators in the BHA's?	
25. Are there any procedures that could be improved to reduce stuck pipe?	

1.13.3.4 *Mud loggers*

1. Have all the mud loggers been on a stuck pipe course? The name of the stuck pipe course they have attended?	
2. When did they attend the courses?	
3. Have the mud loggers attended an appropriate training course?	
4. Stuck pipe poster in the mud logging cabin?	
5. Hole section wall chart displayed in mud loggers' cabin?	
6. Do loggers have a copy of the complete well programme in the mud logging unit?	
7. Do loggers have a copy of the rep's instructions?	
8. Do loggers communicate with the rig floor / Rep every shift.?	
9. Do the mud loggers repeatedly call the rig floor to inform of a formation change and to inform of any trend change during drilling, tripping, running casing, logging?	
10. Loggers attend the pre-shift toolbox talks?	
11. Loggers attend the pre-section drilling brief?	
12. How often do the loggers visit the rig floor?	
13. Do the drillers/assistant drillers visit the mud logging cabin?	
14. Do the loggers have any stuck pipe prevention material.	
15. Other	

1.13.3.5 ***Mud Engineers***

1. Have mud engineers been on any stuck pipe course?	
2. Names of the stuck pipe course they have attended?	
3. When did they attend the course?	
4. Have mud engineers attended a drilling training course?	
5. Does the mud engineer have a well programme?	
6. Is there a well wall chart in the mud lab?	
7. Does the rig carry a pipe lax pill?	
8. Do the mud engineers communicate well with the drilling team?	
9. Does the mud engineer have a clear line of communication to the rig floor?	
10. Do the mud engineers attend the toolbox talks?	
11. Do the mud engineers attend the pre-section drilling brief?	
12. Do the mud engineers provide written instructions on the mud properties?	
13. Are the main mud properties visibly displayed in the shaker area?	
14. Is the hole section wall chart displayed in mud engineer's lab?	
15. Are there stuck pipe posters displayed in the shaker area, sack storage room by the mixing hopper, in the mud engineer's lab?	
16. Are there clear written mud mixing instructions given to the derrickman by the mud engineer?	
17. Is there a regular mud engineer on the rig or do they change frequently?	
18. Is there a mud logging monitor in the mud lab?	
19. Do the mud engineers observe the returns and advise on potential cuttings beds forming?	
20. Other	

1.13.4 Other stuck pipe

1.13.4.1 *Logging*

1. Do the wireline logging crews communicate with the rep prior to logging and note all the evident well data and potential stuck pipe sections?	
2. Is the hole circulated clean prior to logging and does the mud engineer verify the returns?	
3. Does the logging crew carry the complete fishing and stripping over tools together with the relevant procedures?	
4. Other	

1.13.4.2 *Casing*

1. Is the hole circulated clean prior to running casing and does the mud engineer verify the returns with respect to the parameters in the well programme?	
2. Does the rig conduct a pre-casing meeting?	
3. Are there written casing running procedures on the rig floor?	
4. Does the casing tally state the open hole depth entry and the formations?	
5. Is the hole circulated at any time during running casing?	
6. Is there a clear centralisation programme defined on the casing tally?	
7. Is there a full strength casing x/over to drillpipe thread on the rig for each casing job.	
8. Other	

1.13.5 Conclusions and recommendations

This should include information to assist preventing the rig from incurring stuck pipe, stuck casing or stuck logging tools.

1. How do the rig / shift supervisors take an active part in promoting the stuck pipe prevention campaign?	

2. Suggestions for improvement and areas where the campaign requires greater focus?

2 Stuck Pipe Causation

2.1 Causes of Stuck Pipe

Stuck pipe can be defined as a situation where part of a drill string is stationary at the 'stuck point', and the maximum forces applied to that part of the drill string cannot bring it back into motion. When considering a drill string which is run into a clean and cased hole, the downhole forces acting on this drill string are:

- **Gravitational forces**
- **Buoyancy effects**
- **Friction forces (Torque and Drag)**

During the process of drilling, cuttings and solids are generated which may not be removed sufficiently by circulation. In addition, the drilled hole may not be in gauge due to ledges, washouts, etc. These conditions are likely to generate additional forces in the form of overpull or set-down weight, and/or incremental torque. Good drilling practices are aimed at avoiding (or at least minimising) these additional forces, to reduce the chances of stuck pipe.

The conditions that cause overpull, set-down or incremental torque are known as sticking mechanisms, and can be categorised into:

2.1.1 **Solids Related Sticking Mechanisms - Inadequate Hole Cleaning:**

During 'normal' drilling, cuttings can stick the pipe if they accumulate at a restriction (such as the top of the Drill Collars or a stabiliser) when circulation is stopped.

- Cuttings must be circulated away from BHA before stopping the pumps to make a connection'
- Every effort must be made to clear cuttings out of the hole before tripping

The severity of hole cleaning problems will depend on

- Pump rate,
- Cuttings properties (size, shape, density, concentration, and tendency to stick together to form sticky lumps / gumbo),
- Mud properties (weight, viscosity, gel strengths),
- Pipe / Hole properties (annulus diameter, washouts/over-gauge sections, riser length

When drilling deviated wells (>30º inclination) cuttings are likely to accumulate on the low side of the hole, especially when not rotating the pipe (sliding). If this 'cuttings bed' is not removed, the BHA will be pulled into it and may stick the pipe.

When drilling formations that contain pebbles / glacial deposits etc. it will be exceedingly difficult to clean the hole especially if the drilling fluid is water. This is common in shallow sections of many North Atlantic, Arctic wells where the problem is worst due to the large hole diameters.

2.1.2 Reactive Formations / Hole instability

- **Reactive Clay/Shales:** Some Clay/shales chemically react with water, which results in formation swelling. Stuck pipe occurs when highly reactive clay/shales swell, leading to under-gauge hole, high torque, high drag and bit / BHA balling or packing off.
- **Unconsolidated Sands:** Sand deposits can be unconsolidated. at shallow depths, these sands may flow into the well when drilled. Stuck pipe occurs when the sand fails completely and collapses onto the drillstring.
- **Geo-pressured Formations:** Some shales become unstable if the drilling fluid hydrostatic head is insufficient to support the stresses applied via the overburden. This leads to the generation of caving's, which slough into the wellbore. Stuck pipe occurs when the volume of caving's overloads the wellbore, and the drillstring becomes packed off and buried in caving's.
- **Fractured or Faulted Formations:** Fractured / faulted formations consist of mechanically incompetent rock, which collapses into the wellbore. Stuck pipe occurs when the collapsed formation pack offs around the drillstring.
- **Mechanical Junk:** If mechanical junk is either dropped into the well, or is left downhole due to tool failure, stuck pipe can occur when the debris jams the drillstring in place.
- **Cement Blocks:** Stuck pipe occurs when cement blocks from behind casing, or from the shoe track is dislodged and falls onto the BHA, wedging it in place.

2.1.3 Differential Sticking Mechanism

Differential sticking occurs when the differential pressure (overbalance) between the hydrostatic head of the drilling fluid and the pore pressure in a permeable formation is applied to the cross-sectional area of the drillstring. This generates a differential force, which forces a stationary drillstring into the filter cake of a permeable zone.

If the differential force is applied to a drillstring contact area of sufficient length, the pipe will be stuck.

Five conditions must exist for differential sticking to occur, these being:

1. The formation must be permeable.
2. The permeable zone must be covered with filter cake.
3. There must be a static overbalance between hydrostatic head and formation pressure.
4. There must be contact between the drillstring and the borehole wall.
5. Time.

2.1.4 Geometrical Sticking Mechanisms

Geometrical sticking mechanisms occur when the shape or size of the hole is the direct cause of the stuck pipe event. These may be classified as follows:

- **Under-gauge Hole:** Stuck pipe occurs in under-gauge hole when a BHA is run into a section of hole with a smaller diameter. The sticking mechanism is an interference fit between the BHA component diameter and the gauge of the drilled interval.
- **Stiff BHA:** Stuck pipe occurs when a stiff BHA is run into a section of hole directionally drilled with a limber BHA. The moment of inertia of the BHA is too stiff to “bend” around the high localised dogleg, and the BHA becomes wedged in place.
- **Key Seating:** Key seating is caused by an abrupt change in angle or direction in medium soft to medium hard formation. High string tension and pipe rotation wears a slot into the formation. This results in localised under-gauge hole, which causes stuck pipe when a larger section of pipe (i.e. the BHA) is pulled into the slot.
- **Ledges:** Ledges are created when drilling in strata which alternate between hard and soft formations. The soft formations are eroded or washed away creating over-gauge hole, which is interspersed with full gauge hole in the harder rock sections. Stuck pipe occurs when a BHA is run into, or pulled through the ledged area, and becomes jammed against a ledge, or series of ledges.
- **Squeezing Salt:** Mobile Salts deform plastically and squeeze into a drilled wellbore, creating under-gauge hole. Stuck pipe occurs when a BHA is run or pulled into an under-gauge salt section.

2.2 Solids related

2.2.1 Packing off, immediate actions

1. At the first signs of the drill string torqueing up and increase in pump pressure *i.e. primary indication that the hole is packing off.* **Reduce pump strokes significantly**.

   Notes: It is important to realise that the resulting pressure trapped must be maintained less than the formation break down pressure at point of pack off. Undue pressure applied and/or unwarranted mechanical agitation *i.e. backreaming* in a pack-off situation will in most cases only aggravate the situation, potentially further de-stabilise and enlarging the hole. As ***wellbore quality maintenance (Perfect cylinders) is always the primary goal***, attempt to initially work the string, cycling pump pressures and torque into the string *(preferably in the opposite direction to where pack off occurred)* until returns are regained, the hole cleans up, and normal returns are achieved.

2. **If the string packs off** and all returns are lost. **Immediately stop the pumps**, work the string in the opposite direction to which pack off occurred and **bleed down the trapped standpipe pressure** [**NB** *not possible with a non-ported float valve*]. *Note: Bleed down from below pack-off, controlling the rate so as not to further de-stabilise the wellbore or "U" tube solids into the drill string in case they plug the string.*

3. **Commence cycling low pressure** *(i.e. < than the anticipated formation breakdown)* below the pack-off and working the string in “free pipe” interval that may exist. Pressure bleed off rate will act as a primary indicator that the situation is improving.

4. If no progress is made, hold the maximum allowable pressure on the standpipe, worked the drillstring in “free pipe” area and cycle the drill string up to maximum make-up torque.

   a. Continue cycling the torque, watching for pressure bleed off and returns at the shakers. If bleed off or partial circulation occurs, slowly increase pump strokes to maintain a maximum allowable pressure. If circulation improves continue to increase the pump strokes.

5. If circulation cannot be regained, work the pipe between free up and free down weight. **DO NOT APPLY EXCESSIVE PULLS & SET DOWN WEIGHTS** AS THIS WILL AGGRAVATE THE SITUATION (*50k lb max).* Whilst working the string continue to cycle the torque to stall out and maintain a maximum allowable standpipe pressure.

6. **DO NOT ATTEMPT TO FIRE THE JARS IN EITHER DIRECTION AT THIS POINT**

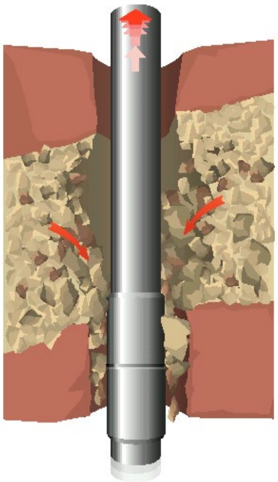
7. If the pipe is still not free once full circulation is established, commence jarring operations in the opposite direction to the last pipe movement. Once the pipe is free, work the string, rotate downwards only if required to clean the hole prior to continuing the trip.

8. During all the above, rotational practices should be given very careful consideration. *E.g. in fragile, pressured tertiary shales etc. unwarranted rotation in a pack off situation will only make matters worse, lending to further hole deterioration, enlargement, and instability*.

   Note: Backream **ONLY** as a last resort.

2.2.2 Unconsolidated formations

2.2.2.1 *Description*



These formations fall into, *induced to collapse* and "flow" via introducing poor practices into the well bore since the sedimentary constituents are loosely packed with little or no bonding between particles, pebbles, or boulders. ***Knowing the drilling limits*** are strongly advised.

Instability will occur when *little or no filter cake is present* or has formed. The un-bonded formation *(sand, gravel, small river-bed boulders etc.)* *cannot be supported by hydrostatic overbalance* as the fluid simply flows into the formation. Sand or gravel then falls into the hole and packs off the drill string. The effect can be a gradual increase in drag over a short interval drilled or can be sudden. This mechanism is normally associated with shallow formation sediments below the seafloor. *E.g. shallow river-bed structures at about 500m in the central North Sea and in also West of Shetlands*.

This mechanism normally occurs:

- While drilling shallow unconsolidated sand formations.

Note: Once these formations induced to de-stabilise they will "flow" into the well where stuck pipe risks and remedial actions required will increase significantly.

2.2.2.2 *Preventative Action*

These formations **need** a strong **filter cake to stabilise the formation**. Seepage loss can also be minimised with adding fine lost circulation material to the drilling fluids. If possible, avoid excessive circulating and rotation (***particularly backreaming***) on connections or when the BHA is being tripped and/or opposite the unconsolidated formations to reduce both hydraulic and/or mechanical erosive, detrimental effects. Sweeping with hi-viscous mud and spotting a gel pill before POOH can assist to build and develop a thin, tough, impermeable filter cake desired. *I.e* ***The primary combatant*** *to assure a stable wellbore from collapsing*.

Controlled tripping speeds with the BHA through this formation will also reduce mechanical damage and risks of wellbore collapse. If pumps are needed, start and stop the pumps slowly to avoid further pressure surges applied to the unconsolidated formations. During drilling control-drill the suspected zone to allow time for the filter cake to build up, minimise annulus loading and cumulative pressure effects that will result. Use sweeps to help keep the hole clean. Shaker, desilter and desander may overload..

A method successfully used offshore in massive sands, is to drill 10m (30ft), pull back to the top of the section and wait 10mins. Note: any fill on bottom when returning to drill ahead. If the fill is significant then ensure the process is repeated every 10m (30ft). At times, it may be impossible to prevent some wellbore collapse and breakout. If so, allowing the wellbore to stabilise itself with the BHA up out of harm's way may be the preferred option.

2.2.2.3 *Rig site indications*

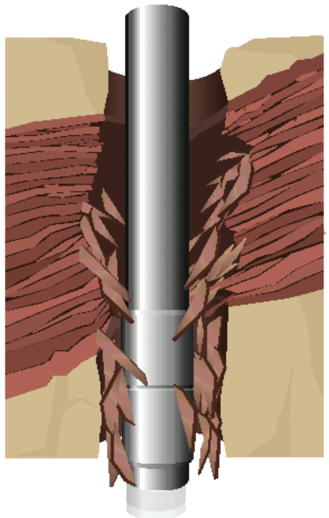
- More common in top, surface, intermediate wellbores.
- Can occur while drilling or tripping.
- Fill on bottom, Increase in torque and pressure.
- Fill on bottom. Overpull on connections.
- Shakers blinding.

2.2.3 Freeing

Follow "pack off procedures" note allowable pack off pressure will probably not be achievable in shallow formations.
Apply low pump pressures (<100-300psi as a general rule of thumb).
Jar in opposite direction to previous operating direction with maximum trip load.
Apply torque and rotation with extreme caution (often this is more of a hindrance than an assist.)

2.2.4 Fractured and faulted

2.2.4.1 *Description*



A natural fracture system in the rock can often be found near faults. Rock near faults can be broken into large or small pieces. If sediments are loose, they can fall into the well bore stick the string.

Even if the pieces are bonded together, impacts from the BHA due to drill string rotation, vibration, and excitation can also result in the formation to fall into the well bore.

This type of "stuck pipe" incident is particularly unusual in that stuck pipe can result during drilling, where in the past, the first sign of a problem has been the string torqueing up and the pipe becoming immediately stuck.

There is a risk of sticking in fractured / faulted formation when drilling through a fault and when drilling through fractured limestone formations.

Warnings can be as formation is drilled, mud logger evaluation, caving's at shaker, hole fill on connections, on bottom up or trips.

This mechanism can occur:

- In tectonically active zones.
- In prognosed fractured limestone.
- As the formation is drilled.

2.2.4.2 *Preventative Action*

Minimise drill string/wellbore agitation, vibration, excitation. Choose alternative RPM's or change the BHA configuration if high shock vibrations are observed.

While tripping or working pipe over such intervals, control trip speed before the BHA enters a suspected fractured/faulted area.

Generally, fractured formations require time to stabilise. Be prepared to spend time when initially drilling and reaming prior to making significant further progress. Circulate the hole clean before drilling ahead. Restrict tripping speed when BHA is opposite fractured formations and fault zones. Start / stop the drill string slowly to avoid pressure surges to the well bore. Ream fractured zones cautiously as often reaming may only further deteriorate the situation.

2.2.4.3 *Rig site indications*

- Wellbore fill on connections.
- Possible losses or gains.
- Fault damaged caving's at shakers
- Sticking can be instantaneous.

2.2.4.4 *Freeing*

If packed off while off-bottom, then follow first actions.

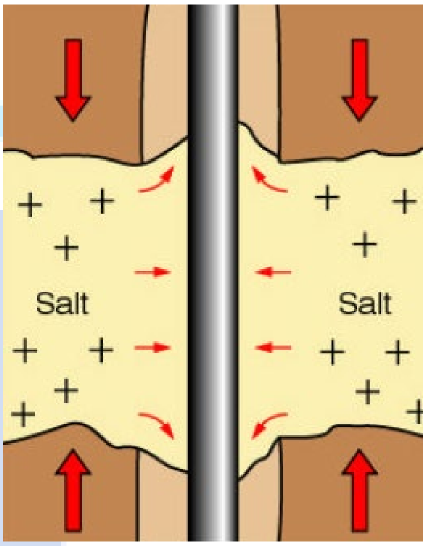
Otherwise JAR in the opposite direction to which the pipe was moving to break up formation debris. Use every effort to maintain circulation.

Circulate high density viscous sweeps to clean debris.

Spot acid if stuck in limestone.

2.2.5 Geo-pressured formations (Salts)

2.2.5.1 *Description*



Salt is the classic geo-pressured formation where the plastic nature of salt formations may result in stuck pipe.

When drilling into salt, stressed will be relieved and the formation will extrude into the wellbore. Often, the intrusion can be measured in just fractions of an inch, but this may be sufficient to cause a bit or stabilizer to become stuck.

Ten magnitude of the stresses and hence rate of movement will vary from region to region but is generally greater for formations below 6000 feet.

Abnormal pressures and flowing salt may be experienced anywhere with unequal relieved stresses, but most commonly occur at the top of a formation or on the flanks of salt domes.

Drilling near a salt diaper presents a special case because of the altered in situ stresses near to the diaper. The behaviour of wells within a few hundred meters of a diaper may be totally different to wells only a kilometre or so away. In general hole problems are accentuated near a diaper.

2.2.5.2 *Preventative*

Select and maintain the right mud system and weight for formation characteristics to be drilled.

The maintenance of gauge or near gauge hole is important when drilling massive salt formations. (Check or wiper trip may be merited as wellbore warning signs and conditions dictate.)

Greatly washed out wellbores will probably result in a poor cement job. This in turn will allow salt behind the casing to creep, impinging on the casing and, in extreme cases cause the casing to buckle.

As salt formations tend to creep and impinge on the drillstring. The only way to stop this process is to drill with a mud weight equivalent to overburden pressure (***approximately 19ppg in the S N Sea and 17ppg in the Gulf of Mexico***). In practice the rate of creep can often be reduced to acceptable levels at lower mud weights, typically 14.0ppg.

The use of eccentric bits to slightly increase the diameter of the hole has proved beneficial in some operations.

Controlled tripping speeds warranted before BHA enters these intervals.

Minimize open hole exposure time.

2.2.5.3 *Rig site indications*

Probably will occur when POH or when RIH after a long period out of hole.
Possible while drilling if formation mobility is rapid (highly stressed)
Sticking will likely result within BHA at Mobile zone depth.
Circulation will likely be unrestricted or slight restriction may be observed.

2.2.5.4 *Freeing*

Apply low pump pressure method (200-400psi as a rule of thumb)
If moving up / down Apply torque, jar in opposite direction to pipe movement with maximum trip load.
Fresh water spotted across the salt may break down the salt to the point of freeing the pipe, however this will do damage to the bore wellbore. If the string cannot be jarred free, or if it is stuck above the jars, it will be necessary to back-off and run a jarring assembly or wash-over.

2.3 Formation instability – General

2.3.1 **General**

Some formations can plastically extrude into the hole and close around the pipe, others can slough and cause a hole to pack off. *E.g. Coal is prone to sloughing, slat will extrude, and shales can do either.* Non cemented sands and gravels can also collapse and slough into the wellbore, resulting in enlarged over gauge wellbore diameters that then result in wellbore cleaning difficulties. Finally fractured and stringer formations such e.g. limestone's can result in a succession of formation components falling into the well form the inter-beds that result, often causing mechanical sticking and further stuck pipe problems around the BHA components.

2.3.2 **Clay / Shales**

On average, Clay / shales constitute more than 75% of rocks drilled during oil and gas exploration. These clay-rich sedimentary rocks are the major source of wellbore instability problems and as such are responsible for more lost time and additional costs than any other drilling problem e.g. *Major operators have stated that shale-related problems account for more than 50% of al wellbore lost drilling time, costing the industry perhaps a few billion dollars per year.*

Most Clay / shales have the potential to cause drilling problems. Some forms of instability caused by ground stresses or excess pore pressures: ***these regarded as having a purely mechanical failure mode***. Other problems are caused by the ***chemical reactions which occur when the formations are exposed to drilling mud***. Often what begins as a chemical reaction then can results in changes to the mechanical shale properties and causes rocks to fail. Chemical effects therefore often firmly linked to the mechanics of wellbore instability.

Clay / Shale stability is governed by several factors, including the weight of the overburden, in-situ stresses, angle, orientation of bedding, moisture content and their chemical composition. Shales can be split into two categories.

2.3.2.1 ***Brittle or sloughing shales***

These shales fail by breaking into pieces and sloughing into the wellbore. Sloughing that can be recognised by large amounts of shale on the shakers from "bottoms up", drag on connections and trips and fill on bottom.

2.3.2.2 ***Swelling Clay / Shales***

Swelling Clay / shales result from the chemical reaction with water and is known as hydration. The clay platelets which make up these clay's / shale's, are pushed apart by the water and the formation expands.

The amount of swelling varies from highly reactive "Gumbo's" to clay's / shale's that will hydrate more slowly. However, any swelling is a potential cause of stuck pipe.

Gumbos will swell very rapidly and dramatically. Given sufficient free water that clay platelets will separate completely, expanding to several times the original volume. The wellbore however can be cleaned through applying controlled rates of drilling but may require reamed as the clays continue to swell.

2.3.2.3 ***Hole Orientation***

Clay / Shales are inherently weaker along the formation bedding planes that across them. Because of this wellbores drilled at different inclinations and directions through the same formation may vary greatly in stability. Increasing the mud weight then required to stabilise the formation, where close monitoring of wellbore parameters, trends and carefully applied drilling practices are required to minimise stuck pipe risks. Particularly at higher inclinations this clay / shale stability problem needs to be geo-mechanically and practically fully assessed.

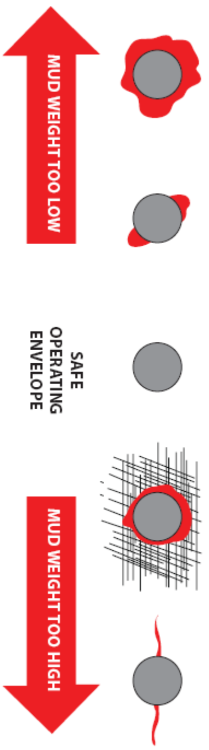
2.3.3 Symptoms and Remedial Action

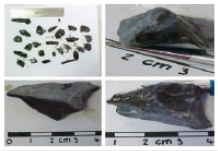
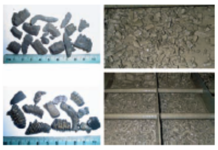
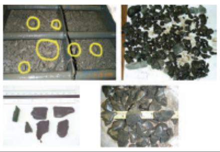
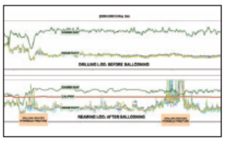
Having planned the well using all available data the risk of mechanical and/or chemical borehole instability will be limited. It is, however, important that should instability occur it should be identified, and suitable remedial action should be quickly adopted.

Indication of the condition of the hole can be inferred from torque and drag measurements, the condition and quantity of cuttings seen at the shakers and variations in mud volumes.

- When drilling clay / shales, monitor cuttings quality as a qualitative measure of inhibition. Extremely Soft clay cuttings will mean insufficient chemical inhibition or, in the case of OBM, would suggest that the water phase salinity is too low.
- High torque values would suggest a tight hole possibly requiring increase in mud weight or an increase in inhibition to reduce the swelling of clays.
- A sudden appearance of large or increased volume of “cuttings” at the shale shakers is indicative of well bore caving.
- An unplanned increased in mud rheology could be due to a build-up of fine solids in the mud which in turn could be an indication of poor inhibition or hole washout.
- The downhole loss of whole mud would indicate that the formation was being fractured using too high a mud weight.
- Difficulty running in the hole could be attributed to ledges, swelling clays or caving formations.
- Finally, a calliper log can be run at section TD.
    - The gauge of the hole will give an indication of whether mud weight and inhibition were at a correct level for that interval.
    - If an oriented 4-arm calliper is used information on stress orientations can be obtained.
    - A typical indication of stress induced borehole instability is the presence of an oval rather than circular hole.
    - Information regarding the two horizontals in situ stresses can be deduced from this type of log.
    - Knowing the direction of the stresses is valuable when planning development wells as the well directions least prone to wellbore problems can be established.
- Figure 4 presents a typical diagnosis to wellbore failures that can then lead to stuck pipe events. Solutions as provided to be adhered to when and as applicable.

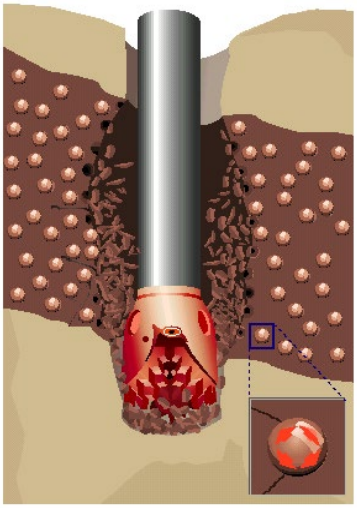
Figure 4: Diagnosing wellbore failures.



CONDITION	CAUSE	SIGNS	SOLUTION
Enlarged Wellbore	Tensile failure along the wellbore circumference caused when shale pore pressure exceeds hydrostatic pressure of drilling fluid column.	 *Splintered shale cuttings exhibit long, concave shape.*	• Stop drilling and increase mud weight • If cavings cannot be controlled, set casing to avoid influx and/or stuck pipe
Wellbore Collapse	Shear failure, occurring when wellbore stresses receive insufficient support from the mud weight. Can be aggravated by changes in wellbore azimuth and inclination.	 *Wellbore cavings exhibit non-parallel, angular edges; may appear gouged.*	• Decrease ROP • Increase flow rate • Increase mud weight gradually until cavings are sparse
Stable Wellbore	Wellbore pressure prevents formation fluid influx or wellbore collapse, and does not exceed fracture pressure.	 *Happy driller, reduced risk and costs.*	• Maintain clean wellbore • Avoid swab and surge pressures • Use real-time modeling to derive optimum mud weight for borehole stability
Rubble Zones	Stress-related failure of brittle rocks. Often natural earth stress fields, especially near salt bodies and active faults.	 *Wellbore cavings are tabular with parallel surfaces.*	• Minimize changes in mud weight and swab/surge pressures • Avoid reaming and mechanical agitation of rubble zone • Monitor trips through destabilized zones • Watch for avalanches and stuck pipe until zone is cased
Fracturing and Ballooning	Fractures open due to increased pressure when circulating mud. Fractures close when circulation stops.	 *Drilling fluid losses are indicative of a ballooning wellbore.*	• Manage fracture growth by reducing ECD and mud weight • Locate fracture using time-lapse logging • Minimize surge pressures on fracture • Monitor and reduce the volume and time trend of flow back • Apply polymer or LCM to damaged interval

2.3.4 Naturally Over pressured Clay / Shale collapse

2.3.4.1 *Description*



A naturally over-pressured clay / shale is where pore pressure greater than the normal hydrostatic pressure gradient.

Naturally, over-pressured formations are caused by under-compaction, naturally removed overburden *i.e. weathering and uplift.*

Insufficient mud weight *(too low or too high)* is the probable cause for wellbore to be unstable and/or collapse.

This mechanism normally occurs in:

- Prognosed rapid depositional clay / shale intervals.
- Can occur during a connection, tripping or while drilling.
- Complete pack off often results.
- Circulation often restricted or impossible.

2.3.4.2 *Preventative action*

Ensure mud weight is well engineered before drilling these intervals. *i.e. maintaining formation in least in-situ stress condition.*

Slowly increase mud weight before drilling into these pressured zones.

Minimise *hole exposure time, swab and surge pressure*

Rigorous use of gas levels to detect pore pressure trends. Use of other information to predict pore pressure trends (*for example Dexp*).

Once exposed do not reduce the mud weight. It may also be the case that the mud weight will need to be raised with an increase in inclination.

Trip, wipe, pump out and as required ream and if ultimately required, *backream with caution*.

Log problem related depth for future trips, running casing etc.

Avoid unnecessary open-hole time exposure or non-essential operations.

2.3.4.3 *Rig site indications*

- Excessive caving's (*splintery*) at shakers.
- Increased torque and drag.
- Gas levels, D exponent.
- Circulation restricted or impossible.
- Wellbore fill.
- An increase in ROP.
- Cuttings and caving's are not hydrated or mushy.

2.3.4.4 *Freeing*

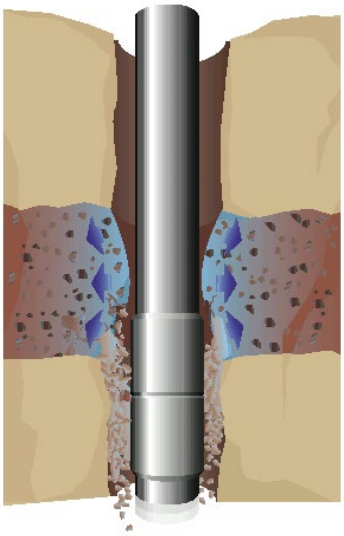
Apply low pump pressure (<200-400psi as a rule of thumb)

Jar in opposite direction to operations when instability occurred at maximum trip load.

Torque and rotating often does not help. It will often make matters far worse.

2.3.5 Induced over pressure shale collapse

2.3.5.1 *Description*



Induced over-pressure shale occurs when the shale assumes the hydrostatic pressure of the well bore fluids after a number of days exposure to that pressure.
When this is followed by no increase or a reduction in hydrostatic pressure in the well bore, the shale, which now has a higher internal pressure than the well bore, collapses in a similar manner to naturally over-pressured shale.

This mechanism normally occurs:

- In WBM.
- After a reduction in mud weight or after a long exposure time during which the mud weight was constant.
- In the casing rat hole.

2.3.5.2 *Preventative action*

Non water-based muds prevent inducing over-pressure in shale.
Do not plan a reduction in mud weight after exposing shale.
If caving's occur, utilise appropriate wellbore cleaning practices.
Trip, wipe, pump out and as required ream and if ultimately required, backream with caution.
Log problem related depth for future trips, running casing etc.
Avoid unnecessary open hole time or non-essential operations.

2.3.5.3 *Rig site indications*

- Cuttings / caving's show no sign of hydration.
- Caving's (splintery) at shakers.
- Tight hole in casing rat hole.
- Increased torque and drag.
- Circulating restricted or impossible.
- Wellbore fill.

2.3.5.4 *Freeing*

Apply low pump pressure (<200-400psi as a rule of thumb)
Jar in opposite direction to operations when instability occurred at maximum trip load.
Torque and rotating often does not help. It will often make matters far worse.

2.3.6 Reactive formations

2.3.6.1 *Description*

A *water sensitive shale* is drilled with less inhibition than is required. The shale absorbs the water and swells into the well bore. The reaction is 'time dependent', as the chemical reaction takes time to occur. However, the time can range from hours to days.

This mechanism normally occurs:

- When using WBM in shales and clays in young formations.
- When drilling with an incorrect mud specification. Particularly, an insufficient concentration of inhibition additives in OBM and WBM such as salts (KCl, CaCL), glycol and polymer.

2.3.6.2 *Preventative action*

Use an inhibited mud system. Maintain the mud properties as planned. The addition of various salts (*potassium, sodium, calcium, etc.*) will reduce the chemical attraction of the water to the shale. Various encapsulating (*coating*) polymers can be added to WBM mud to reduce water contact with the shale. Monitoring mud properties is the key to detection of this problem.

Open-hole time in shale should be minimised. Regular wiper trips or reaming trips may help if shales begin to swell. The frequency should be based on exposure time or warning signs of reactive shales.

Ensure hole cleaning is adequate to clean excess formation i.e. clay balls, low gravity solids etc.

Trip, wipe, pump out and as required ream and if ultimately required, backream with caution.

Log problem related depths for future trips, running casing etc.

2.3.6.3 *Rig site indications*

- Hydrated or mushy cavings.
- Shakers screens blind off, clay balls form.
- Increase in LGS, filter cake thickness, PV, YP, MBT.
- An increase or fluctuations in pump pressure.
- Generally occurs while POOH.
- Circulation is impossible or highly restricted.

2.3.6.4 *Freeing*

POH slowly to prevent swabbing.

See First Actions.

2.3.7 Vertical Hole cleaning

2.3.7.1 *Description*

In vertical wells solids i.e. cuttings and caving's can settle and form layers of solids or cuttings resulting in the BHA components becoming stuck in solids bed.

OR

Cuttings and caving's slide down the annulus when the pumps are turned off and pack-off the drill string. Good vertical hole cleaning means removal of sufficient solids from the well bore to allow the reasonably unhindered passage of the drill string and the casing.

There are several main reasons for solids not being cleaned out of the well bore. These are:

- A low annular flow rate. E.g. Notably in wellbores > 12-1/4"
- Inappropriate mud properties. E.g. drilling with sea-water
- Insufficient circulation time. E.g. Check bottoms up times.
- Inadequate mechanical agitation,
    - More applicable in vertical wells when wellbores are enlarged or washed out..

Note: If any of the above are missing, good hole cleaning will be very unlikely.

2.3.7.2 *Preventative Action*

- Maximise the annular velocity.
  - Consider the use of a third mud pump.
  - Consider using larger drill pipe.
- Ensure circulation times are adequate.
  - Monitor the cuttings returns at the shakers.
- Maximise mechanical agitation of cuttings beds.
  - Reciprocation.
- Optimise mud properties.
  - increase YP in near vertical wells.

2.3.7.3 *Rig site indications*

- Over-pulls increasing while POOH from TD (e.g. in first 7-10 stands).
- Erratic pump pressure.
- Poor weight transfer to bit.
- Absence of returns at shakers.
- Presence of re-ground cuttings (LGS)

2.3.7.4 *Freeing*

See Immediate First Actions
Refer to Hole Cleaning section for more information.

2.4 Differential Sticking

2.4.1 General

Differential Sticking is possible in most drilling operations, except for special underbalanced drilling situations. When the pressure exerted by the mud column is greater than the pressure of the formation fluids. In permeable formations, mud filtrate will flow from the well into the rock or sand, building up a filter cake. A pressure differential will exist across the filter cake, which is equal to the difference in the pressure of the mud column and the formation. Thus, if the drill string touches the filter cake, any part of the pipe which penetrates or becomes embedded in the cake will be subject to a lower pressure than that the part which remains wholly in the well. If the pressure difference is high enough and acts over a sufficiently large area, the pipe may become stuck.

Differentially stuck pipe usually happens when the drill string has been stationary for a period. When pipe is differentially stuck the pipe cannot be reciprocated or rotated however circulation at normal standpipe pressures is possible.

The force required to pull differentially stuck pipe free depends on:

a) The difference in pressure between the wellbore and formation. Any overbalance adds to side forces which may exist due to the deviation of the wellbore.

b) The surface area of pipe embedded in the wall cake. The thicker the wall cake or the larger the OD of the tubular the greater the contact.

c) The coefficient of friction between the pipe and the wall cake is a significant factor being directly proportional to the sticking force. It tends to increase with time, making it harder to pull the pipe free. Wet clays adhere to metals.

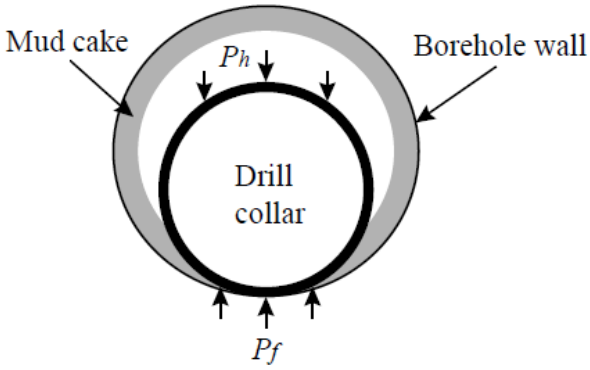


Figure 5: Ph is hydrostatic pressure and Pf is formation pressure.

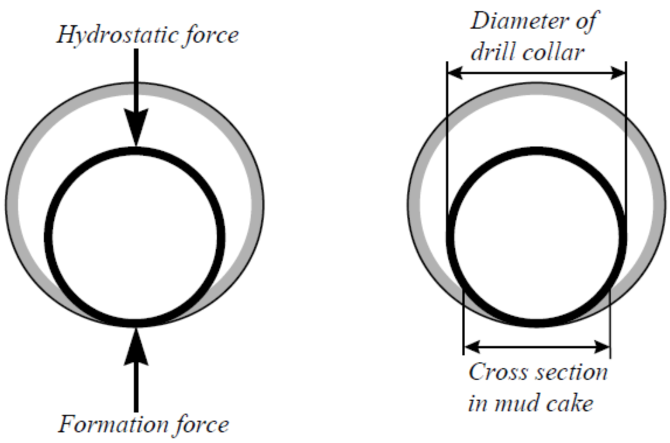


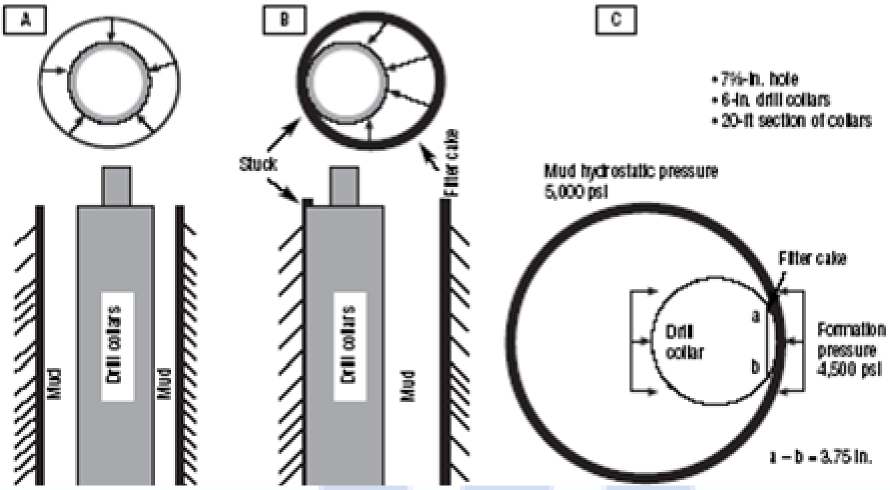
Figure 6: Hydrostatic force and formation force that are acting on the drill collar.

Example: *drilling at 5,000ft with 11.8ppg mud in a 3,000psi formation to 5,100ft. At 5,500' a 4,500psi formation is encountered and the mug weight is increased to 15.7ppg. The pressure differential at 5000ft. would be approximately 1000psi. A string of 5" drill pipe with 25% contact with the tube would create a suction equal to 392,500lbs. This example excludes the effects of friction.*

2.4.2 Description

Differential sticking occurs when the drill string is held against the well bore by a force as illustrated in figure 7. This force is created by the imbalance of the hydrostatic pressure in the well bore and the pore pressure of a permeable formation. When the hydrostatic pressure is greater than the pore pressure the difference is called the overbalance. The resultant force of the overbalance acting on an area of drill string is the force that sticks the string.

Figure 7: Mechanics of differential sticking



This mechanism normally occurs:

- With a stationary or very slow-moving string.
- When contact exists between the drill string and well bore.
- When an overbalance is present.
- Across a permeable formation.
- In a thick *filter cake*.

2.4.3 Preventative Action

Any action taken to reduce or eliminate one or more of the above causes will reduce the risk of differential sticking.

Well design
Where possible design casing setting depths to minimise overbalance across potential sticking zones, i.e. design for minimum overbalance. Limit mud weight to the minimum required for well stability and control.

Mud
Use OBM where possible. Keep fluid loss to a minimum. Maintain a low concentration of LGS. Keep gels low.

Hole Size (inches)	Recommended % LGS
17.5	10-15
12.25	8-10
8.5	5-8
6	5-8

Stationary string
KEEP THE STRING MOVING. Pre-plan to minimize the down time for operations that require the string to remain static (*surveys, minor repairs, etc.*). Consider rotating the string during drilling and tripping connections while BHA is opposite high risk sticking zones.

Well bore contact
Minimise BHA length when possible. Maximise BHA stand-off. Use spiral drill collars.

Rig team awareness
The rig team can be made aware of the depth of permeable formations and the estimated overbalance in those zones.

2.4.4 Rig site indications

- Over-pull on connections and after surveys
- No string movement
- Full unrestricted circulation
- Losses
- High overbalance
- Permeable formation exposed in open hole

2.4.5 Freeing

Immediate Actions in the event of Differential Sticking

1. Establish that Differential Sticking is the mechanism,
    a. i.e, stuck after a connection or survey with full unrestricted circulation across a permeable formation (*Sand, Dolomite and possibly Limestone*).
2. Initially circulate at the maximum allowable rate.
    a. This is to attempt to erode the filter cake.
3. Slump the string while holding at least 50% of make-up torque of surface *pipe (unless mixed string of pipe is being used*).
    a. Use an action similar to what would be used with a bumper sub - see note below.
4. Pick up to just above the up weight and perform step 2 again.
5. Repeat 2. & 3.
    a. Increasing to 100% make-up torque until string is freed or until preparations have been made to: either
        i. *spot a releasing pill*
        ii. *conduct "U" tube operations*

2.5 Mechanical & Well Bore Geometry

2.5.1 Other Stuck Pipe Types - First Action

Guidelines for freeing stuck pipe other than Pack-offs and Differential sticking.

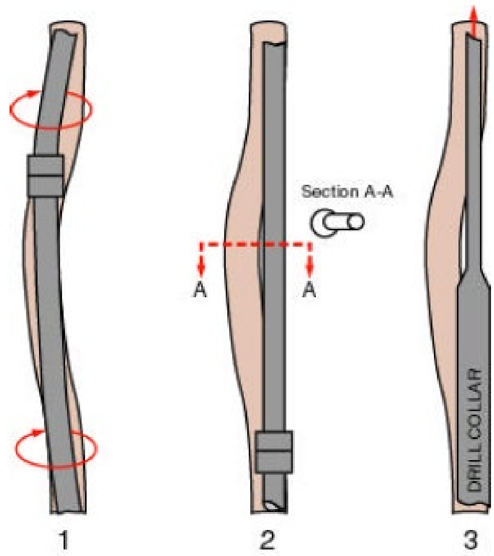
Ensure circulation is maintained.

1. If the string became stuck while moving up, (*apply torque)* jar down.
2. If the string became stuck while moving down, do not apply torque and Jar up.
3. Jarring operations should start with light loading (*50k lbs*) and then systematically increased to maximum load over a one-hour period. Stop or reduce circulation when.
   a. cocking the jars to fire up and
   b. jarring down. Pump pressure will increase jar blow when jarring up, so full circulation is beneficial *(beware of maximum load at the jar - see jarring section of this section*)
4. If jarring is unsuccessful consider acid or other suitable remedial pills if conditions permit.

2.5.2 Key Seating

2.5.2.1 *Description*

Key seating is caused by the drill pipe rotating against the bore hole wall at the same point and wearing a groove or key seat in the wall. When the drill string is tripped, the tool joints or the BHA are pulled into the key seat and become jammed. Key seating can also occur at the casing shoe if a groove is worn in the casing.



This mechanism normally occurs:

- At abrupt changes in angle or direction in medium-soft to medium-hard formation.
- Where high side wall forces and string rotation exists.
- While pulling out of the hole.
- After long drilling hours with no wiper trips through the dogleg section.

2.5.2.2 *Preventative Action*

Minimise dogleg severity. Perform reaming and/or wiper trips if a dogleg is present. Consider running string reamers or a key seat wiper if a key seat is likely to be a problem.

2.5.2.3 *Rig Site Indications*

- Occurs only while POOH.
- Sudden overpull as BHA reaches dogleg depth.
- Unrestricted circulation.
- Free string movement below key seat depth if not already stuck in key seat.
- Cyclic overpull at tool joint intervals on trips observed.

2.5.2.4 *Freeing*

If possible, apply torque and jar down with maximum trip load. Back ream out of the hole. If present use key seat wiper.

2.5.3 Under-gauge Hole

2.5.3.1 *Description*

Drilling hard abrasive rock wears the bit and the stabiliser gauge and results in a smaller than gauge hole. When a subsequent in-gauge bit is run, it encounters resistance due to the under-gauge section of hole. If the string is run into the hole quickly without reaming, the bit can jam in the under-gauged wellbore section.

This mechanism normally occurs:

- After running a new bit
- After coring
- When a PDC bit is run after a roller cone bit
- When drilling abrasive formations

Other sticking mechanisms may give similar effects particularly mobile formations.

Core heads are often slightly smaller than bit sizes and cored sections should be reamed when running in with a bit to drill ahead. Failure to ream in to the hole can result in the bit jamming in the under-gauge section of cored hole.

2.5.3.2 *Preventative Action*

Use suitably gauge-protected bits and stabilisers. Consider the use of roller reamers. Always gauge all BHA components both when running in and pulling out of the hole. Ream suspected under-gauge sections. Slow the trip speed down before the BHA enters an under-gauge zone.

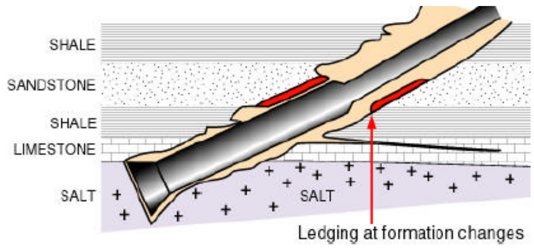
2.5.3.3 *Rig site indications*

- Pulled bit or stabilisers are under-gauge.
- Occurs only when RIH.
- Sudden set down weight.
- Circulation is unrestricted or slightly restricted.
- Bit stuck near the bottom of the hole or at the top of a cored section.

2.5.3.4 *Freeing*

Jar up with maximum trip load. Do not jar down. Consider the use of an acid pill. Consider applying torque as a last resort.

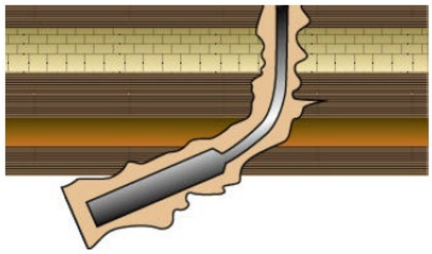
2.5.4 Ledges and Doglegs



2.5.4.1 *Description*

Ledge: The well bore passes through rock of varying types and ledges develop at the interfaces between layers of differing hardness.

Doglegs: While drilling a well bore, the characteristics of the rock cause the bit to be deflected and can result in a change in direction. Likewise when drilling with a directional BHA, sudden changes in angle can cause a kink in the well bore direction. Sharp deviations in wellbore direction are called doglegs.



These mechanisms usually occur:

- When an unsuitable BHA is run.
- After a change in BHA.
- Prognosed hard soft inter-bedded formations.
- Prognosed fractured / faulted formations.
- After wellbore directional changes.
- While POOH.

2.5.4.2 *Preventative Action*

Ledging will be reduced by running a packed-hole assembly. Minimise direction changes in the well bore. Minimise BHA configuration changes when in formations likely to produce ledges. Consider reaming trips.
Make a log of depths of ledges and other anomalies.
It can help to get a large-scale printout from the mud loggers and to draw a scale BHA on a separate piece of paper. The paper BHA can be positioned at the depth of any over-pulls and it is easy to see if any of the stabilisers are hanging up at the same point. By using this technique, it is simple to keep track of multiple problem zones and to communicate expected problem depths clearly to the driller.
Survey with sufficient frequency, increasing the well bore survey frequency will:

- Assist in evaluating/reducing well bore tortuosity.
- Reduce the number of BHA changes.

Slow trip speeds before BHA enters the suspected ledge zone or dog leg. Avoid prolonged circulation across soft inter-bedded formations. Limit initial set-down weight to less than 50% of down drag to minimise momentum effects when running into a tight zone. Do not start angle building operations too close to the shoe (start at least 30m below old hole TD).

2.5.4.3 *Rig site indications*

- Sudden erratic overpull or set-down.
- Problems are at fixed depths.
- Full circulation is possible.

2.5.4.4 *Freeing*

If moving up when sticking occurred, apply torque and jar down with maximum trip load. If moving down, jar up with maximum trip load. Do not apply torque. If string cannot be wiped past obstruction, and if able to, lightly backream or ream very slowly past problem as rotation will assist the stabilisers and/or other tools to roll past the ledge.

2.5.5 **Junk**

2.5.5.1 ***Description***

Debris that has fallen into the hole from surface or from downhole equipment, which falls down the well bore and jams the drill string. This mechanism usually occurs:

- Due to poor housekeeping on the rig floor.
- The hole cover not being installed.
- Downhole equipment failure.

2.5.5.2 ***Preventative Action***

Encourage good housekeeping on the rig floor and regular inspection of handling equipment. Keep the hole covered at all times. Inspect downhole equipment before it is run in the hole and again as it is being run through the rotary table. Inspect slip and tong dies regularly. Install drill string wiper rubber as quickly as possible.

2.5.5.3 ***Rig site indications***

- Repair/maintenance work recently performed on the rig floor.
- Missing hand tools / equipment.
- Circulation unrestricted.
- Metal shavings at shaker.
- Sudden erratic torque.
- Inability to make hole.

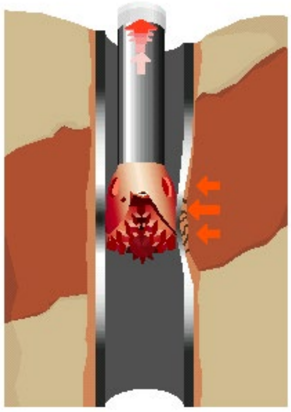
2.5.5.4 ***Freeing***

See First Actions

2.5.6 Collapsed Casing / Tubing

2.5.6.1 *Description*

Casing collapses either if pressure conditions exceed its original rated collapse pressure or the original collapse pressure rating of the casing is no longer valid due to casing wear and/or corrosion. Casing wear due to friction or corrosion decreases the effective collapse pressure rating of the casing, through decreased wall thickness. Collapse is often discovered when the BHA is run into the hole and hangs up inside the casing.



This mechanism can occur when:

- The collapse pressure of the casing is exceeded during a pressure test where an annulus leak is occurring. The collapse pressure of the casing may be less than expected, due to casing wear.
- The casing fluid is evacuated, causing the casing to collapse.
- The casing is buckled due to aggressive running procedures.

2.5.6.2 *Preventative measures*

Avoid casing wear, refer to casing wear guidelines. Good cementing practices should be used. Cement to surface or as high as possible. Use corrosion inhibitors in fluids.

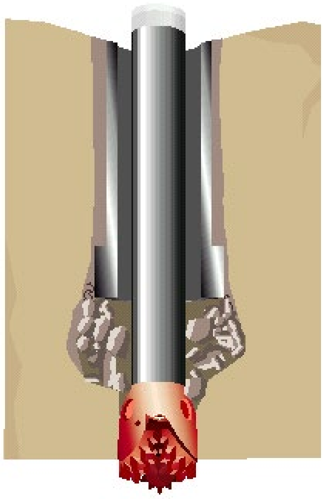
2.5.6.3 *Rig site indicators*

- BHA hangs up when RIH.
- Caliper log shows collapsed casing.

2.5.6.4 *Freeing*

Jar out of the hole if possible.

2.5.7 Cement Blocks



2.5.7.1 *Description*

The drill string becomes jammed in the hole by cement blocks falling around the string.

This mechanism normally occurs when:

- Hard cement becomes unstable around the casing shoe, open hole squeeze plugs and kick-off plugs.

2.5.7.2 *Preventative Action*

Allow sufficient curing time for cement before attempting to kick off or drill out. Ream casing shoe and open hole plugs thoroughly before drilling ahead. Limit casing rat-hole length to minimise a source of cement blocks. Slow the trip speed down before the BHA enters the casing shoe or the plug depth.
Use of fibre additives to the cement can increase its integrity. Maintain sufficient distance between the paths of platform wells to reduce the possibility of cement blocks from adjacent well bores.

2.5.7.3 *Rig site indications*

- Circulation unrestricted.
- Cement fragments.
- Rotation and downward movement may be possible.
- Erratic torque.

2.5.7.4 *Freeing*

See First Actions

2.5.8 Green Cement

2.5.8.1 *Description*

When the drill string is inadvertently run into cement, the cement can flash set. The top of the cement may be higher than prognosed. The increase in pressure generated by the surge of the BHA causes the cement to flash set.

Circulation is attempted with the bottom of the drill string in soft cement. The increase in pressure causes the cement to flash set.

A high penetration rate is used when cleaning out recently set cement, below which is un-set cement which flash sets.

This mechanism normally occurs:

- While running into the hole to dress off cement

2.5.8.2 *Preventative Action*

Do not rely solely on surface samples. Know the cement setting time, but do not assume it will be set when you trip into the hole. Know the calculated top of cement (*TOC*) before tripping in hole but always expect it to be higher. Do not rely on the weight indicator to find the top of the cement. If the cement is not set you may not see any indication on the weight indicator when you run into it.
In large hole sizes begin washing down two stands above the theoretical top of the cement. Consider starting to 'wash through' 3-4 stands above the theoretical cement top in small hole sizes. If set down weight is observed when tripping in hole after a cement operation, pull back 2 stands before attempting circulation. Control drill when cleaning out soft cement.
Consider pre-treating the mud system with chemicals prior to drilling out the cement.

2.5.8.3 *Rig site indications*

- Increase in pump pressure leading to inability to circulate.
- Loss of string weight.
- Sudden decrease in torque.
- Green cement in mud returns, discoloration of mud.

2.5.8.4 *Freeing*

Bleed off any trapped pump pressure. Jar up with maximum trip load. Attempt to establish circulation.

2.6 Parted String

Even with the more challenging and today complex wells drilled the incidence of parted strings occur less often than in the not so distant past. Improved quality assurance and better managed control of tools and equipment systems, maintenance, inspection procedures, monitoring systems, materials and coatings all contributing to a reduction in occurrence. The biggest challenge when fishing a parted string is in the interpretation of the condition of the fish top.

A drill string may part due to any of the following reasons:

- A twist-off after becoming stuck
- A washout
- A back-lash, unscrewing the string
- Junk wearing through a tubular
- Metal Fatigue

2.6.1 A twist-off after becoming stuck

When working at shallow depths without the benefit of a torque limiter. As the string becomes stuck the torque will build up so rapidly that a twist-off can readily occur, particularly with today's higher rates Top drive units etc. If the work string is in poor condition this can and will therefore more likely happen at any depth with or without limiters. A twist off can be the most difficult type of parted string to fish due to the possible condition of the fish top. Knowing torque limitations and setting equipment below these rating is therefore paramount to mitigate such incidences.

2.6.2 A Washout

Turbulent flow created in a damaged connection may cause and/or create a washout. Washouts have therefore even occurred at the most minute offset created in a drill collar after boring from either end. If washouts are not detected early, it can weaken the washed-out area until it ultimately fails and the pipe twists off. A washout in a tubular can in turn washout the formation reducing the annular velocity in the washed-out area diminishing wellbore cleaning. Any time there a drop in standpipe pressure that cannot be accounted for at the surface, the string should be pulled immediately.

2.6.3 A back lash, unscrewing the string

A drill string that alternately sticks then releases while drilling can result in a build-up of torque which, when released, rotates the lower portion of the string at an accelerated rate. The inertia of the lower string can make the string back-off. In a gauged area of the wellbore, the string would be screwed back together; in a washed-out area, it might be necessary to run special tools to engage the fish. This can also occur when the strings is lifted off bottom while torque is in the string.

2.6.4 Junk wearing through a tubular

Junk pushed into a soft formation can later damage tubulars rotating against the junk. It is always best to remove rather then push junk aside.

2.6.5 Metal Fatigue

Metal Fatigue can cause a string to fail under normal operating parameters. This occurrence can only be reduced by establishing the working life of components and replacing components when that time has been reached. **Note:** *Equipment failure can be virtually eliminated by using and fully implementing a well-established maintenance program.*

2.6.6 Parted strings summary

1. Parted strings are in most cases easier to fish than stuck pipe.
2. However, in an open wellbore, the likelihood of recovery diminishes with time.
3. If a connection is looking up, a screw-in assembly with jars should be run.
4. If the fish top cannot be screwed into, an overshot with a jarring assembly should be run.
5. The condition of the bottom of the string pulled after a parted string, the wellbore condition at the top of the fish and length of fish neck will all determine what tool will be run.

2.7 Bottom hole assembly changes

2.7.1 Planning stage

Run what is needed.

Do not plan a stiffer assembly to follow a flexible BHA, without assuring that necessary care is to be taken when tripping back into the wellbore.

2.7.2 Rig site precautions

Gauge all bits and stabilisers before and after each trip. Assure correct gauge rings are used.

Unless torque records clearly show the point at which the bit/BHA became worn consider reaming a longer section as drilled by the previous bit.

When running a BHA of increase stiffness, expect to ream.

If wellbore is suspected to be under-gauge, extreme caution must be applied when tripping into the hole.

2.8 Stuck logging tools

Logging companies have procedures for attempting to free a stuck logging tool. This will involve opening and closing all callipers and other moving parts.

The most common mechanisms are:

1. **Differential Sticking of the cable**

   The wireline cable is held against a permeable formation by the cable tension.

   Filter cake builds and differential sticking occurs.

   This is identified by surface and downhole tension measurements differing; lack of tension indicated on the tool's internal tension measurement signal compared with positive indications of overpull on the surface tension instruments.

   The common solution is to strip over the tool.

2. **Mechanical sticking of formation testing tool and side wall core tools.**

   The sample catchers of the formation testing tool are pressed into the side wall of the formation to catch a sample of formation fluid or a pressure reading. The probe can become mechanically stuck in the formation. Sidewall core tools fire bullets to the wall of the hole. These bullets are attached to the tool by wire ties. The bullets sometimes stick in the formation.

   This type of sticking has been freed in the past by working the tool between the maximum working overpull and slack-off for up to 1 hour.

   Minimise the time the tools and cable are stationary. Agree sampling times with the department requesting the data.

   It is possible that these tools can become differentially stuck at the same time as being mechanically stuck.

3. **Geometrical sticking of the logging tool due to its shape.**

   Calipers, pad tools and other angular shaped sections of logging tool can hang up on ledges, casing shoes etc.,

4. **Key seating of the cable**

   The wireline cable can become key seated in a similar manner as a drill string. Slow pulling and minimum cable tension will reduce the risk of this.

3 Freeing Stuck pipe

3.1 Freeing stuck pipe flowchart

Use the flowchart (Figure 8) and tables 5 and 6, to help decide the best plan of action. The next page highlights the various freeing methods for each stuck pipe mechanism. Subsequent pages explain these methods in more detail and give useful equations, graphs, etc. for freeing the pipe.

Figure 8: Freeing Stuck Pipe flowchart

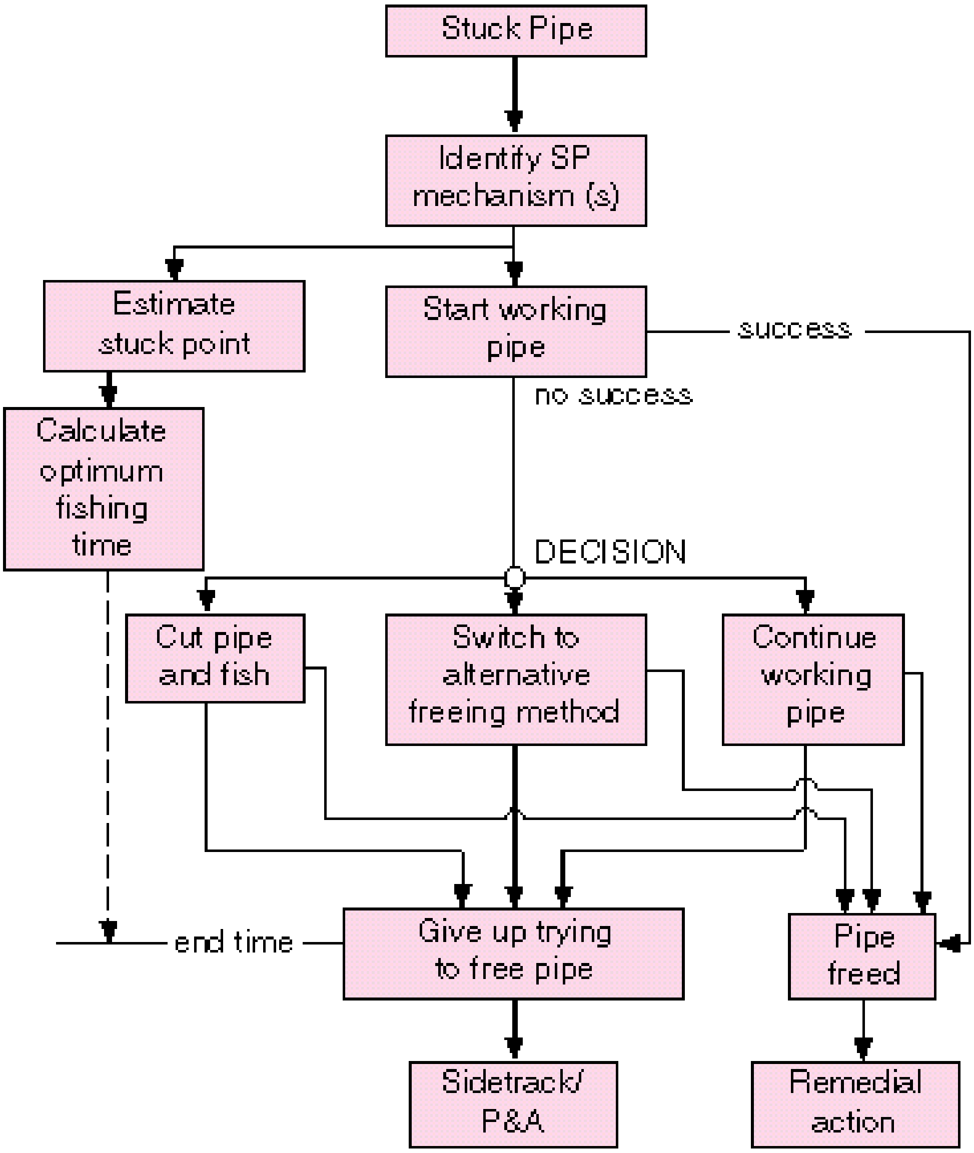


Table 4: Stuck pipe freeing table

STUCK PIPE MECHANISM	METHOD OF FREEING STUCK PIPE		
	PRIMARY	SECONDARY	ADDITIONAL INFORMATION
DIFFERENTIAL STICKING	Slump string and rotate. Maximum force from start.	U-tube or pipe release agent.	Check well control/stability before deciding to U-tube
KEY SEATING	Work string down and rotate. Increase force gradually.	Formation-specific (if possible).	Look at formation. Treat for formation (salt, l/st, clay).
UNDERGAUGE HOLE	Work string up. Maximum force from start.	Formation-specific (if possible).	Look at formation. Treat for formation (salt, l/st, clay).
WELLBORE GEOMETRY	Work pipe in opposite direction to trip. Increase force gradually.	Formation-specific (if possible).	Look at formation. Treat for formation (salt, l/st, clay).
HOLE CLEANING	Work string down and increase circulation.	Packed-off hole procedure.	Concentrate on downwards pipe movement and full circulation.
JUNK	Work string up and down. Increase force gradually.	RIH to overgauge section to lose junk.	
GREEN CEMENT	Jar/pull up. Maximum force from the start.	Pump acid pill.	
CEMENT BLOCKS	Work string up and down.	Pump acid pill.	

Table 5: Stuck pipe freeing table continued

STUCK PIPE MECHANISM	METHOD OF FREEING STUCK PIPE		
	PRIMARY	SECONDARY	ADDITIONAL INFORMATION
COLLAPSED CASING	Work string down. Increase forces gradually.	Specialist job - refer to town	
UNCONSOLIDATED FORMATION	Work string up and down. Circulation increase force gradual.	Packed-off hole procedure	Concentrate on downwards pipe movement and full circulation.
SALT	Work pipe in opposite direction to trip. Max force from start.	Pump freshwater pill	
PLASTIC CLAY	Work string up and down. Increase force gradually.		
FRACTURED/ FAULTED FORM	Work string up and down. Max force from start.	Pump acid pill if in limestone or chalk	If hole packed-off, increase forces gradually.
GEOPRESSURED FORMATION	Work string up and down. Increase forces gradually.	Packed-off hole procedure	Concentrate on downwards pipe movement and full circulation.
REACTIVE FORMATION	Work string up and down. Increase forces gradually.	Packed-off hole procedure	Concentrate on downwards pipe movement and full circulation.

3.2 Mechanical freeing

(All Stuck Pipe) In all instances the first response to stuck pipe is to try to free it mechanically.

3.2.1 General Freeing

Always apply the freeing forces in the opposite direction to the direction of movement immediately before sticking. ie:

- **tripping in:** overpull/jar upwards
- **tripping out:** slack-off/jar downwards

Establish circulation if possible. Know the effect of circulation on the jars (see jarring page).

Working the pipe downwards

Work torque into the string down to the stuck point. Normally 0.75 turns/1000ft. Know the effect of torque on the jars. Slack off and let the jars fire down.

Working the pipe upwards

Check whether force should be increased gradually, or maximum force applied from the start, then follow the appropriate action:

Either

Start working the pipe. Initially jar with 40-50,000lbs over the force required to trip the jar. Increase the force gradually over an hour. Do not exceed the maximum agreed overpull.

Or

Start working the pipe to its limits. Remember: work the pipe, allow the jar to fire, then work the pipe to its limit with the jar un-cocked.

3.3 Overpull calculations

3.3.1 Initial Overpull

½ x BHA weight below jars (in air)
0.85 x Tensile strength of weakest component

(whichever is less)

3.3.2 Calculation of Maximum Overpull

Estimate weak point of string. (Usually drill pipe at surface, but check if running a mixed string eg. 6.5/8" / 5" drillpipe.)

Maximum overpull at weak point (T_m) = 0.85 x Tensile strength at weak point

Calculate weight of drill string in air above weak point (W_{sw}).

(W_{sw} = 0 if weak point at surface).

Maximum overpull on weight indicator W_{im}):

$W_{im} = W_b + T_m + W_{sw}$

Calculation of Overpull at stuck point (T_o):

$T_o = W_i - W_b - W_s$

where:

W_b = block weight

W_i = weight indicator reading

W_s = weight of drill string in air above stuck point

Note:

W_i must never exceed W_{im}

3.4 Jarring calculations

3.4.1 Load Required to Trip Jar Upwards

$$L_s = W_i - W_j + L_j + D_h - P_f$$

3.4.2 Load Required to Trip Jar Downwards

$$L_s = W_i - W_j - L_j - D_h - P_f$$

where:

L_s = surface load to operate jar (lbs)

W_i = weight indicator reading (lbs)

L_j = desired jar load (lbs)

D_h = hole drag (lbs)

W_j = weight of BHA in air below jar (lbs)

P_f = pump open force (lbs)

Remember: Ensure jar is un-cocked before working pipe to the limit.

Tripping out - jar down
Tripping in - jar up

Pump Open Force only applies when circulating.

3.4.3 Effect of Circulation

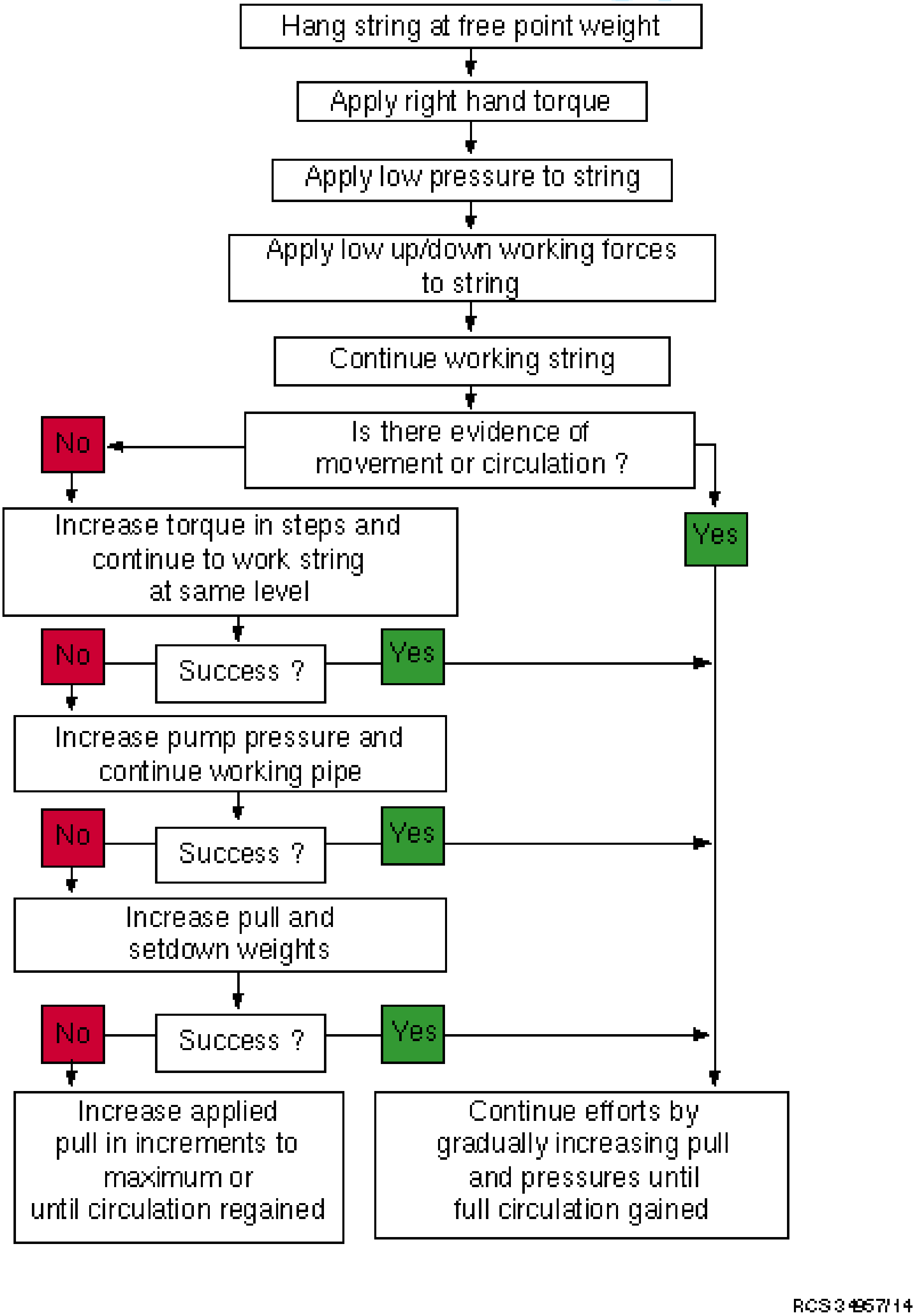
Table 6: Circulation effects when jarring

Jar Type	*Jar up*	*Jar down*
Hydraulic	Harder to cock Larger impact & impulse forces	Easier to cock Smaller impact & impulse forces
Mechanical	Harder to cock Easier to trip Forces unaffected	Easier to cock Harder to trip Forces unaffected

3.5 Packed off hole

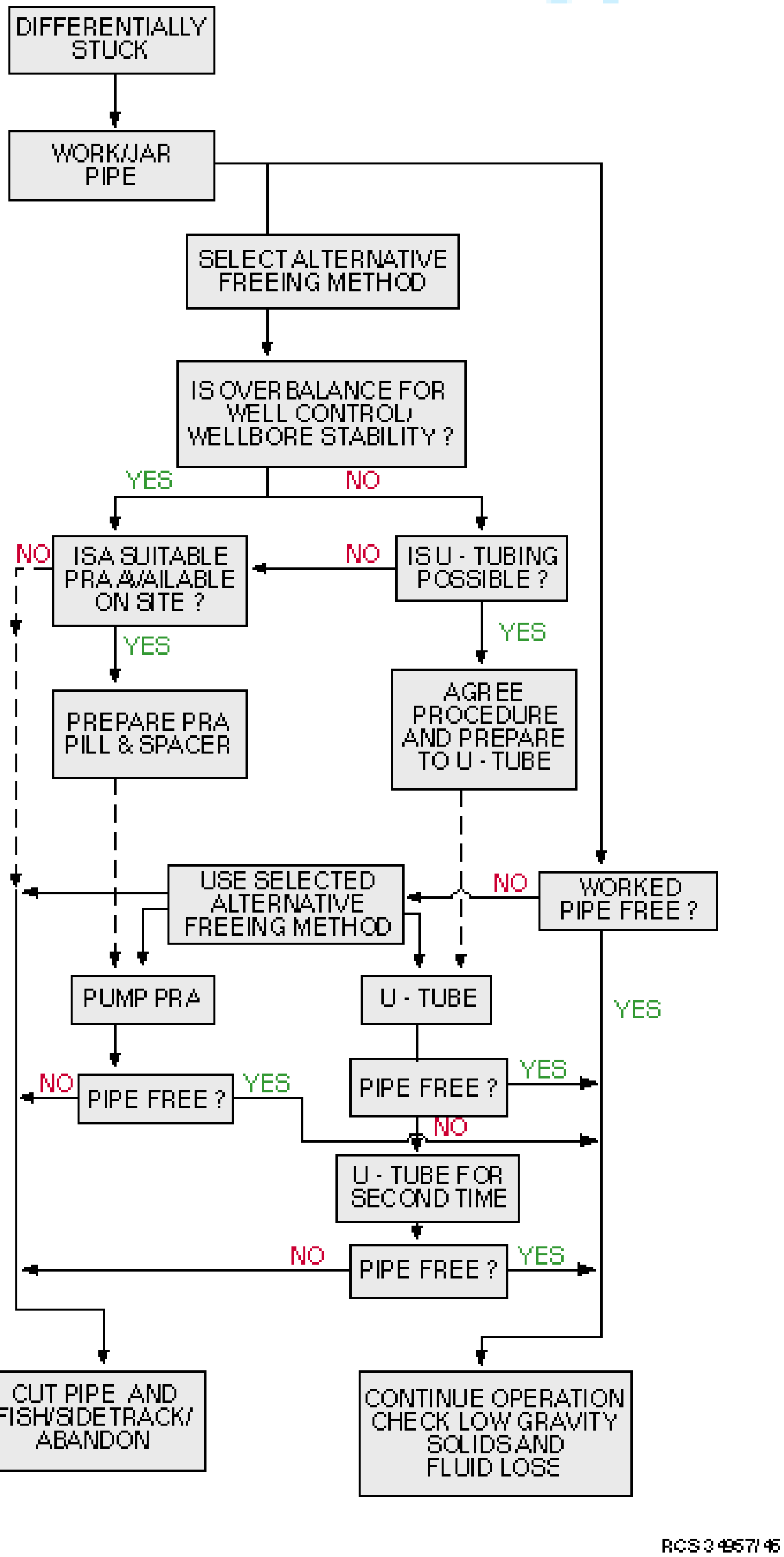
(Wellbore Instability/Hole Cleaning)

Figure 9: Suggested method to try and establish circulation



3.6 Differential sticking

Figure 10: Method Selection for freeing stuck pipe



3.7 U-Tubing *(Differential Sticking)*

This can be a quick and effective freeing method, but it has restricted applications. U-tubing should never be used where there is any danger of inducing a well control incident, and generally not used in potentially mechanically unstable formations as it tends to shock the formation. However when U-tubing has been used once it can be used many times afterwards with no danger of further damage to the formation. If U-tubing is an option an exact procedure should be agreed with the local Drilling office.

If the string does not release immediately the well can be left in a drawn-down state for two hours while still working the pipe. After two hours circulate back to mud and attempt to U-tube free again, maybe to a lower hydrostatic pressure. After two attempts consider fishing or side-tracking.

3.7.1 U-Tubing Procedure

(There cannot be a solid float valve in the string for this procedure.)

Install a full-opening Kelly-cock valve or similar into drillstring at working height on the rig floor below the top drive, circulating head, or kelly.

Perform all calculations as per the worksheet on the next page. These calculations are for U-tubing to formation pressure. If a different final hydrostatic pressure is required i.e. above or below formation pressure) calculate an equivalent formation pressure and use it in the worksheet.

Close the annular preventer with minimum closing pressure.
Reverse circulate the required volume of light fluid into the annulus via the choke line with the cement pump (for accuracy). **CLOSE THE CHOKE.**

Work RH torque into the string (±0.75 turns/1000ft) and slack off. Vent the drill pipe above the Kelly=cock through the standpipe to allow air to be sucked in.
Bleed off the back pressure on the choke in stages. Monitor the return of light fluid accurately via trip or strip tank (while working pipe).

Work the pipe vigorously at each bleed-off stage. Once it is moving keep it moving. Open the annular preventer and circulate back to mud. (If there is any danger of gas, circulate through the choke before opening the annular.)

3.7.2 U-Tube calculations

3.7.2.1 *Variables*

Table 7: Variables definitions

PP	Formation pressure at zone of interest [SG] (or maximum formation pressure)
PP_2	Formation pressure at 2nd zone of interest
TVD	True vertical depth of zone of interest [m]
TVD_2	True vertical depth of 2nd zone of interest
MDX	Actual length of light fluid column [m]
MDA	Actual length of air column in pipe after U-tubing [m]
MW	Mud density in hole [SG]
WW	Density of light fluid to be pumped [SG]
CH	Height of choke line [m]
CC	Capacity of choke line [bbl/m]
Ann	Capacity of drillpipe/casing annulus [bbl/m]
DP	Capacity of drillpipe [bbl/m]

3.7.2.2 *Calculation Procedure*

Plot a graph of Choke Pressure, PCH (y-axis) against Volume Bled Back, VA (x-axis).

A. Calculate VA (equations 3 & 4)

B. Mark VA on the x-axis.

C. Calculate PCH (eqns 1 & 7). Mark PCH on the y-axis.

D. Join VA and PCH to show how pressure should fall during bleed off.

E. Mark PCH above VA. This is the max drawdown on the formation.

If the pressure reduction does not follow the chart when bleeding off, then a well control problem or lost circulation can be inferred.

Equations

True Vertical height of light fluid in choke/annulus after U-tubing = X m

$X = (MW - PP) \times TVD \div (MW - WW)$

True Vertical height of mud in annulus after U-tubing = Y m

$Y = TVD - X$

Volume of light fluid in annulus/choke after U-tubing = V bbls

$V = (CH \times CC) + [(MDX - CH) \times Ann]$

True vertical height of air in drillpipe after U-tubing = Am

$A = (MW - PP) \div (MW \times TVD)$

Volume of air in drillpipe after U-tubing = V_A bbls

$V_A = MDA \times DP$

Total volume of light fluid to be pumped = V_o bbls

$V_o = V + V_A$

Max drawdown on any other formation in the well = DR psi

$DR = ((Pm - PP_2) \times 1.421 \times TVD2)$

$Pm = X \times WW + [(TVD2 - X)\ MW] \div TVD2$

(If $TVD2 < X$, then $Pm = WW$)

Initial pressure on choke after pumping but before bleed off = P_{CH}

$P_{CH} = X1.(MW - WW) \times 1.421$

If PP > MW then PCH given by:

$[(X_1.(MW - WW)) + (TVD.(PP - MW))] \times 1.421$

X_1 = True vertical height of light fluid after pumping

3.8 Spotting fluids *(Differential Sticking)*

Unlike U-tubing, there are no hydrostatic restrictions on using pipe release agents 'PRA'. For environmental compliance, however, ask the mud engineer or the local Fluids Group to recommend which PRAs can be used.

Any PRA pill should be spotted within 4 hours of sticking for best results. After 16 hours there is little chance of the pill working so the method should not be considered. The graph below shows the probability of the pipe coming free against soaking time in hours.

This can be used to calculate the time a pill should be left to soak before circulating out and backing off.

As a rule of thumb soak for a minimum of 20 hours and a maximum of 40 hours.

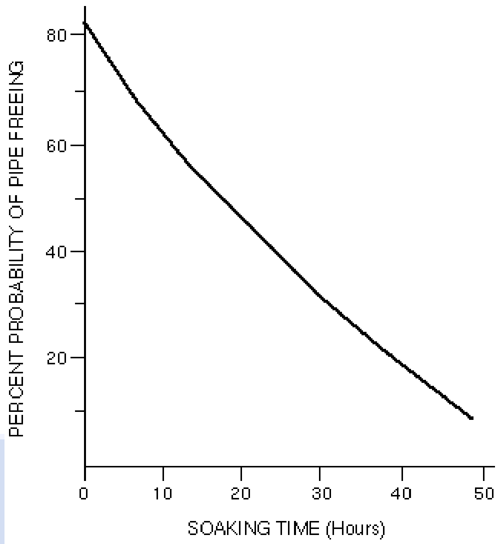


Figure 11: Percentage Probability of Pipe freeing

3.8.1 Procedure

Mix the PRA pill 1.5 times larger than the annulus volume adjacent to the uppermost permeable section in which the pipe is stuck or could become stuck. The pill should be 1-2ppg (0.1- 0.2 SG) heavier than the mud.

Prepare a 50 -100bbl low YP spacer (base oil, brine, seawater) for pumping ahead of the pill. Check the spacer is compatible with both the mud and the PRA pill.

Check well control considerations also.

Spot the spacer and the pill at the maximum flow rate possible. This is necessary to get the PRA behind the pipe where it is stuck.

Leave the pill to soak until the pipe is free or the decision is made to give up. Do not circulate out and replace if the pipe does not appear to be freeing; this is not effective.

Work the pipe while the pill is soaking slack off 20,000lbs, work RH torque into the string (±0.75 turn/1000ft), release torque and pick up. This will work the stuck point down the hole a few inches or a few feet each time until the pipe 'suddenly' pulls free.

3.9 Freshwater pill *(Salt)*

CHECK EFFECT ON WELL CONTROL BEFORE DECIDING TO PUMP A FRESHWATER PILL.

3.9.1 Important Points:

Pill volume should be enough to cover the stuck zone and leave 20bbl inside the drill string. Detergent may be added to the pill to remove any mud film on the borehole wall.

If OBM is in the hole pump a viscous weighted spacer ahead of the pill e.g. XC polymer & Barite. Get the mud company to advise.

Work the pipe while the pill/spacer are being prepared and pumped. Maintain a maximum overpull on the pipe while the pill is soaking.

If the pipe is not free after two hours circulate the pill out and repeat the procedure.

3.10 Inhibited HCl pill *(Cement/Limestone/Chalk)*

CHECK EFFECT ON WELL CONTROL BEFORE DECIDING TO PUMP AN ACID PILL. REMEMBER TO READ THE ACID SAFETY PRECAUTIONS BEFORE STARTING MIXING.

3.10.1 Important Points:

Pill volume should cover the stuck zone. Get the mud company to advise on formulation.

Typical pill strength 7.5 - 10% HC1.

Pump the acid pill quickly, with large water spacers ahead and behind to minimise mud contamination.

Work the pipe while the pill is soaking. The drill string should be free within a few minutes as the acid works quickly. The pill should be circulated out after about 5 minutes.

Note: HCl can weaken tool joints and hi-strength (S135) pipe so consider inspecting tubulars once recovered.

3.12 Freeing Logging Tools

The following is an operational guide developed and a description of the various tools used when stripping over logging cable. Notes of recommendations and lessons learned are included in the text.

3.12.1 Fishing Logging Tools

1. When the wireline company arrives on site for any logging job, check their fishing equipment. Check all crossovers are correct for the drill string in use. Correct overshot and grapple sizes are being used. Hang off ‘T’ bar and circulating sub with slotted hang off insert are all correct. Request for two hang off ‘T’ bars to be on site. 'C' plates to hang off the cable for the pipe size in use must be available, with extended handles to prevent floor hands trapping their fingers when using the ‘C’ plates. The wireline engineer should have an ample stock of cable end stops to make the cable into male and female fishing latches.
2. The wire line overshot is made up of guide bowl, (*various diameters available*), Overshot bowl and top sub furnished with NC (*IF*) threads. It is advisable not to use too large a guide, *e.g., for an 8½" hole use a 5" guide*). After dressing the overshot with the correct sized grapple, the 3 components are screwed together, torqued up and lightly tack welded. This is to prevent the fine threads in the overshot assembly backing off whilst running in the hole. There is a no-go ring fitted in the top sub. The male fishing latch, attached to the logging cable in the hole, should not be able to pass through this no-go. If the cable breaks above the head or the female upper fishing latch fails, the drill string can be pulled out of the hole and the stuck cable recovered. The fishing head will be secured in the no-go ring. Check the male fishing latch does not pass through the ring; if it does, decrease the diameter of the no-go ring, which can be done by a welder.
3. Check with the wireline engineer that the weak point assembly will pass through the no-go ring. If the weak point is broken at any time to recover the cable, the broken weak point assembly must be able to pass through the no-go ring. When the fish is inside the grapple assembly, circulation through the overshot is possible via two, approx. ¾” inch diameter, holes at the top of the overshot bowl.
4. Hold a safety meeting with all concerned so that the wireline engineer can explain the operational procedures. Good communications between the winch operator and the wireline engineer on the rig floor are essential. Make sure there are four radios available (*two for backup*).
5. Double check the pipe tally and adjust the top of fish with respect to the logger's depth and the Driller’s depth. Do not use HWDP unless no other drill pipe is available as the smaller ID of HWDP may restrict options at a later stage.

3.12.2 Procedure for Stripping Over Wireline Cable

1. Install the pulleys, one high in the derrick, below and to one side of the Crown. This should be positioned as not to interfere with the top-drive. On the top-drive motor surround, hook or travelling block, install a pulley to enable the logging cable to run up and down without snagging.
2. Logging unit pulls approx. 1000 lb. tension on the cable in the hole. The cable 'T' clamp is installed. If there are two 'T' clamps, install both. The cable can slip so tighten up the screws carefully. Before installation check the brass inserts of the 'T' clamp are not worn; if they are, replace them.
3. Logging unit slackens off the cable and lands out the 'T' bar on the rotary table. Cut the cable leaving plenty of slack to allow for the overshot length and for fitting a cable end stop. **Note: Advise all unnecessary personnel to stay clear of the loop left in this cable. If the cable slips injury to personnel can occur.**
4. Pass the cut cable through the overshot assembly. Install the cable end clamp and male fishing latch. The other end of the cable is attached to the logging winch is also clamped off and made up to the female fishing latch. Two weighted sinker bars are attached to this cable to help to lower the cable through the stands of drill pipe.
5. A stand is picked up in the elevators and lowered into the mouse-hole to bring the top connection level with the monkey board. The logging cable at the truck end is raised to the monkey board and the derrickman installs the cable head into the pipe. The stand is picked up and positioned over the top of the overshot assembly sitting in the rotary table. (Fig 3)
6. The cable is lowered down through the pipe and latched onto the cable head. The logging winch picks up the connected cable and the 'T' clamp is removed. Before removing the 'T' clamp leave the connected cable hanging for 5 minutes with 1000 lbs tension to check the connections are solid. Screw the overshot into the pin connection of the stand and very carefully torque the connection with the rig tongs.
7. The stand is run into the hole and set in the slips. Check that the cable is running through the pulley on the top-drive, hook or travelling block; if not, stop and reposition the pulley. The cable can then be moved up or down to position the lower fishing latch above the connection. The land-off 'C' plate is slotted over the wire and positioned with its lower lip inside the pin connection. The cable is then slacked off and the lower latch allowed to bottom out on the 'C' plate. **Note: the floor hands must be careful not to get their fingers trapped underneath the 'C' clamp, thus extended handles are necessary.** The cable should have approx. 1000 lbs tension on it at all times to prevent any "bird nesting" caused by slack cable.
8. The operation continues as above. Once a few stands have been run, to speed up winch movements, the logging cable at the drill floor level and at the Wire line drum can be "flagged" as this distance travelled will always be approximately the same. The operation must not be hurried, the driller checking his weight indicator and the logging winch operator monitoring his line tension.
9. The logging cable at the surface should be checked for any broken strands of wire. This can occur with the continual bending of the wire as the derrickman introduces the female latch into the stands of pipe at the monkey-board level. Also, rapid wear can occur with the movement of the cable in the pulley situated at the top-drive. It is good practice to cut off 300 ft of cable and fit a new latch as a precaution against cable failure. Cuts and re-heads should be made every 7500 ft.
10. At the shoe, land off the male latch on the 'C' land-off plate as usual and install the circulating sub over the top of the protruding male latch. Latch the upper cable and pull the connected latches above the top of the circulating sub. Remove the 'C' land-off plate and screw the circulating sub into the drill pipe box connection. A slotted land off collar is slipped over the wire and allowed to drop onto a collar inside the circulating sub. Lower the logging cable and allow the male latch to land off on the slotted collar. (*Be sure the slotted collar is level and fully down against the stop machined in the circulating sub. It has been known for the slotted collar to be lying at an angle, when the latches are disconnected, the slotted collar slips over*

the cable and is lost down the pipe). Disconnect the latches so that the male latch is now sitting proud of the circulating sub by some 8 inches.

11. To avoid damaging the male latch, pick up a single of drill pipe or a stand and screw the stand or single and top-drive to the pin connection of the circulating sub. Circulate through the assembly. Record strokes versus pressure for various SPM's.
12. Disconnecting the circulating sub is the reversal of the procedure outlined above. Be careful not to damage the male latch protruding from the top of the circulating sub.
13. Continue running in the hole, taking care to monitor cable tension. There have been several failures when attempting to recover stuck logging tools. These were due to the wireline overshot picking up debris and becoming plugged whilst running in the open hole. A plugged overshot can still be run in the hole because the cable can easily move through the debris. Sometimes circulation may not be possible. It is recommended to install the circulating sub and circulate, every 10 stands in vertical wells and every 5 stands or more frequently in deviated wells. This is to flush any accumulated debris from the overshot.
14. Although it takes time to install and remove the circulating assembly, there are significant disadvantages being unable to successfully fish a stuck logging tool which is still connected to the logging cable. If tools with neutron sources cannot be fished, they may have to be side-tracked or the result may be a costly fishing job.
15. Approx. 50ft. above the fish, install the circulating sub and record pressures versus strokes. There are 2 different procedures for going over the top of the fish.
16. The preferred method is: To have the cable latched with 1000 lbs tension. The overshot is then lowered over the stuck logging tool and when the tool bottoms out inside the grapple, the cable tension being monitored in the logging truck will increase. When the tension picks up by approximately 1000 lbs the string is stopped. The cable tension is reduced at surface and the string can be further lowered to ensure the fish is securely caught inside the grapple. Be careful while lowering the string as the stuck logging tool may bend or be broken. (*Obviously if the fish is on bottom, this cannot be done*). It may be safer to pick the string up to check on any overpull, thus ensuring that the fish is caught. Once the decision is made that the fish is caught, the string can be positioned to enable installation of the circulating sub. A check of pressures before and after fish engagement will verify if the fish is caught.
17. Alternatively, the string can be lowered whilst circulating. Thus when the fish enters the grapple and the overshot guide bowl, there will be an increase in circulating pressure. The mud will be circulating through the 2 x ¾” inch holes instead of through the guide bowl. The disadvantage of this is that the logging cable below the overshot will slacken and may develop a loop or a kink when the string is lowered. This will prevent the fish entering the overshot. Consequently, the cable may break or become stuck between the fishing neck and the overshot.
18. For pulling out with the fish it is recommended to pull 5 stands with the logging cable still attached to the fish, just in case the fish slips out of the grapple. This can be done by allowing the cable to go slack inside the pipe whilst still being latched together. After 5 stands if the fish is still attached, the weak point can be broken, and the cable pulled to surface. The 'T' clamp is attached to the cable at the top of the pipe in the slips. The male and female cable fishing heads are cut off and a knot is tied. Both free ends being carefully taped. The cable is tensioned up to support all the cable in the pipe and the knot left for five minutes before the 'T' clamp is removed. A careful check on the upper pulley is made as the knot passes over. The wireline depth spooler must be removed at the logging truck to allow the knot to be reeled onto the drum. If the weak point will not break for whatever reason, the cable can be broken. Install the 'T' clamp and with the pipe in the slips close the elevators around the 'T' clamp. Ensure all personnel are off the drill floor. Raise the blocks and break the cable. The cable will fall inside the pipe and thus will need to be cut every 100-200 ft when pulling the pipe.

3.12.2.1 *Conclusions on Stripping Over Wireline with Drill Pipe*

1. It is obvious that the overshot must be completely clear of debris to enable the fish to enter the grapple. Thus, time spent on circulating will pay dividends, even if one half day is added onto the trip time. Frequent circulation is necessary to ensure that the overshot does not become plugged with debris.
2. If the overshot becomes plugged, *(although this is not likely if circulation is maintained as outlined above*) it may be possible to still force the overshot onto the top of the fish.

Case summary

Experience shows that when an overshot was plugged because circulation was not possible, 2 stands were removed with the cable still attached to the fish. The theory behind removing 2 stands was that the cable may dislodge the debris from the upward moving overshot and thus hopefully circulation would be regained. Unfortunately, this was not the case. The debris was so hard packed that the cable weak point was broken as the pipe was moved upward, due to the cable being firmly held by the debris. The resulting slack in the cable inside the pipe, combined with no circulation, indicated that the grapple had engaged the fish 70 ft higher up than Driller's depth tally. It took 12 hours of careful tripping to find out the fish had not been caught. A better plan, even though circulation was not possible, would have been to continue lowering the string over the fish until an increase in cable tension was observed. Thus, the fish may have been able to enter the grapple in spite of the accumulated debris. The worst that would have occurred would have been the breaking of the weak point - as happened in any case.

3.13 Free Point Indicators (FPI)

3.13.1 Free Point Determination

NOTE: If the jars are still operating, minimise the number of stretch and torque readings above the jars to necessary calibration runs only. Attempt to establish the free point using FPI stretch measurements first. Attempting stretch and torque together early is time consuming and could result in trapped torque affecting stretch and torque readings. Once a preliminary free point is established from stretch measurements, verify that torque can be worked down to that point or lower for determination of deepest back-off point.

1. If the drilling jars are not firing, a rough free point depth can be estimated from drill pipe stretch calculations prior to wireline unit arriving on location. This rough depth is of limited value in deviated holes or holes with relatively shallow dog legs. It is accurate to only 200 to 300ft in deeper holes but can give useful starting depths for the FPI tool runs.

Straight-hole stretch values:

- 3.5 inches stretch per 1000ft of free 5", 19.5ppf drill pipe with 50klbs overpull.
- 5.0 inches stretch per 1000ft of free 6.5/8", 27.7ppf drill pipe with 100klbs overpull

2. If drilling jars are not stuck, fire up and un-cock jars prior to RIH with wireline tools. For remainder of free point determination and back-of, do not go below slack-off weight required to re-cock jar.

3. Run in hole with FPI tool to maximum depth possible within the drill string if the jars are operational or to 500ft below estimated free point from stretch calculations if the jars not operational. Run CCL correlation log to minimum 500ft above the suspected stuck point and correlate BHA/formation depths using a paper BHA model

4. After CCL correlation, begin running FPI stretch tests. Minimise intervals tested if good indication of stuck pipe point is known (*e.g. jars firing*). Stretch readings should be taken at mid-joint and the same amount of overpull should be taken each time (50klbs recommended). The initial stretch test reading should be in a section known to be free, for use as baseline reading.

3.13.2 Stretch test procedure is as follows:

1. Ensure pipe is in tension by pulling the up weight plus 10k lbs.
2. Open the tool anchors.
3. Slack off cable according to recommended specifications, typically 2 inches per 1000ft.
4. Pull 50k lbs tension in 10k lb increments and record percentage free on free point data readings and on pull and torque chart
5. Repeat stretch test at each point to check that FPI reading is consistent.
6. Return to anchor setting point (*up weight plus 10k lbs*)
7. Pick up cable slack and close anchors.
8. Slack off to pre-stuck down weight then pick up to pull 10k lbs over up weight in preparation for the next check depth
9. Move to next FPI point and repeat this sequence until the stuck point is identified. Establishing down to 30% free is sufficient.
10. Once a preliminary free point is determined from stretch, commence torque FPI tests beginning at deepest 100% free stretch interval if believed stuck in drill pipe. Take a reading in the bottom of the drill pipe, the bottom of the HWDP and the top drill collar if a BHA free point indication is observed from stretch test.

3.13.3 Torque test procedure is as follows:

1. Ensure pipe is in tension by pulling the up weight plus 10k lbs.
2. Open the tool anchors.
3. Slack off cable according to wireline company recommendations, typically 2 inches per 1000ft.
4. Apply RH torque (*0.75 to 1 turn per 1000ft depth*) to maximum of 80% of drill pipe make-up torque. Work torque down the string by pulling maximum 50k lbs over up weight and slacking down to the pre-stuck down weight. Current (Amps) to top drive, rotary or line pull on tongs used to hold RH torque will decrease as torque is transferred down the hole. When sustained working of pipe fails to reduce the amperage or the tong line pull, record the percentage free.
5. Release torque slowly, work pipe, and count turns returned to ensure that no trapped torque remains. Failure to work out all the trapped torque will give erratic torque readings subsequently.
6. Return to the FPI tool anchor setting point (*up weight plus 10k lbs*).
7. Pick up cable slack and close anchors.
8. Move to next FPI point and repeat this sequence until the stuck point is determined. Establishing down to 50% free is sufficient.

   NOTE: If you are unable to work torque down to the stretch free point depth, it is unlikely that a successful back-off can be made at that depth. Alternatives such as pipe cutter tool should be considered. Normally, an 80% free reading in both torque and stretch is recommended for best chance of successful back-off.
9. Upon completion of FPI tool torque measurements, review the BHA component depth vs. lithology log to determine the best back-off depth. If possible, the back-off point should be selected in an interval which improves the chance of getting back onto the fish or as deep as possible if an immediate side track option is selected. Potential washed out intervals and under gauge section are the worst back-off points to choose.
10. Utilise the FPI tool to accurately determine the neutral point weight at proposed back-off depth prior to POH with the FPI tool to apply the required Left-Hand torque for the back-off attempt.

3.13.4 Back-offs

1. In a high proportion of wells, when using the FPI tool, the stuck point has always been the joint of pipe below the jars. Questionable stuck points immediately below the jars may be due to the internal mechanism of the jars. Free travel is possible in the jars' internal mandrel even when the string below is stuck. Stretch will only be transmitted once the jar is fully open. The string weight used for the back-off or FPI tool readings can be gauged on this jar opening or closing weight, except when this cannot be seen, as in a deviated or horizontal hole.
2. Torque in tortuous well bores takes time to apply and monitor.
3. Compensation for line creep and stretch is important. Regardless of the charge size, placement is the key to success. Pulling additional tension in the drill string may be the key to getting the shot to the correct back-off point.
4. Wireline pack-off systems will allow immediate circulation after shooting. Critical time will not be lost while the wireline is pulled from the well.

3.13.5 Information Required Before Freeing Operations Start

Rig readiness

- Safety - e.g. potential for falling objects.
- Tonne miles on block line

Drill string information

- *Drill pipe:*

Yield of drill pipe tube.

Yield of drill pipe tool joint - *combined torque & pull calculations*

Onset of Buckling

MUT used (make up torque)

- *BHA*

Weight of BHA below jars

Position / formations adjacent, *Paper BHA model*

- *Jars:* *for further information see Jar section*

Maximum pull while jarring with an hydraulic jar.

Jar firing force envelope - i.e. force required to cock and fire jars taking into account drag and jar friction.

Jar firing delay time (Hydraulic jars).

Jar pump open force - is pressure trapped in the string.

Well bore information:

- Formation & characteristics.

Current formations exposed.

Other areas of likely sticking on way out of hole after freeing the stuck string.

- Hole condition.

Up, down & free rotating weights.

Drag chart.

3.13.6 Back off shots

3.13.6.1 *Important Points*

Minimise the time between the free-point survey and running the charge. The free-point can move up the hole with time with an unstable wellbore, or differential sticking.

Back-off success is almost certain (with the correct charge) if pipe torque and stretch are 80-85% free. For deviated wells only attempt to back-off with 50% or more free torque (back-off possible with less than 25% free stretch).

Work LH torque worked into the string and down to the back-off point as recommended in the table. Take the time to ensure torque is worked down to the back-off point before firing the shot.

Table 8: No of turns to effect back off.

Depth (ft)	Turns/1000ft
Below 4000ft	0.25-0.50
4000-9000ft	0.50-0.75
9000+ft	0.75-1.00

Limit surface torque to 80% of the drillpipe make-up torque.

Calculate the string weight in air to the back-off point. Pull on pipe to ensure neutral weight at the back-off point when firing. (Incorrect weight is a common cause of back-off failure.)

If the back-off is successful, pull up and work the pipe while the wireline is removed. Circulate bottoms up before pulling the pipe.

3.15 Stuck pipe hole cleaning

3.15.1 Hole Cleaning

3.15.1.1 *Monitoring Cuttings Returns at the Shakers*

The practice of monitoring the volume rate of cuttings and caving's being circulated out of the wellbore at the shakers has proven a worthwhile exercise in different areas of the world.

Practices employed may be to:

- Monitor and maintain wellbore cleaning efficiency
- Eliminate related torque problems in complex directional or ERD (*extended reach*) wells.
- Warning when the wellbore is loaded, and a potential pack-off situation is occurring.
- Gain better understanding of wellbore behaviour. *(for example: failure cycles, caliper / removed volume relationship).*
- Provide a clearer indicator that the wellbore is being cleaned after a pack-off has occurred and string has been freed.

3.15.1.2 *Discussion*

It is recommended that rigs should have procedures in place for monitoring solids volume rate of returns etc. Here Mud Loggers and mud engineers should be regularly monitoring the volume rate of cuttings and caving's returned. This information should be passed on to both the rig floor and the Senior Drilling Representatives. e.g. *a simple method used in several locations is to simply measure, every hour, the time taken to fill a 5gallon bucket with solids coming over the shakers.*

After freeing the string, once the pack-off material has been circulated out of the hole, the solids rate at the shakers will often increase by 150%. For a particular operation and hole size, normal trends for the volumetric flow rate can be established by regular observation (*the 5 gallon bucket method)* and used as a hole problem warning trend.

It is believed that in many pack-offs occur immediately after a connection and notably while backreaming (where this should only be required if absolutely deemed necessary) and/or within the first single after a connection. Here it is obviously important that the BHA should be circulated clear prior to stopping the pumps.

3.15.1.3 *Cuttings Catchers*

The quantity of cuttings coming over the shakers at surface compared to the theoretical volume cut by the bit can give important information on hole cleaning efficiency and hole stability. This can provide early warning signals of worsening hole conditions.

There are currently three existing designs of automated machinery which measure the quantity of cuttings coming over the shakers and which have been recently field tested. Two mud logging companies are also field testing their own prototype cuttings catcher designs.

All field trials have encountered equipment problems. Assurances have been given by all the manufacturers that these problems can be ironed out. However, there is no cuttings catcher on the market today which is operationally fit for purpose.

Most data from field trials is therefore erroneous and none has demonstrated any real time utilisation of the data. Post well analysis of the data has met with limited success, e.g. only two from the seven known field trials has provided 'reasonable' artificially calculated calliper's.

A majority remain sceptical concerning the application of the data, both real time and post well, primarily due to several assumptions and corrections which are necessary to convert a mass of cuttings at surface to a volume of drilled hole. The theory appears to have received limited attention from the manufacturers or other oil companies.

As a stand-alone hole cleaning and stability monitoring device the cuttings catcher has severe limitations. Interfacing the cuttings catcher information with the information from the mud logging unit has the potential to provide an effective hole cleaning and hole stability monitoring system. Combining the cuttings catcher information with the mud logging unit information, several possible uses and applications have been identified:

- To provide a stuck pipe prevention tool.
- To provide the drill crew with timely information regarding hole cleaning efficiency.
- To optimise drilling fluid properties and pump rates.
- To produce an artificially derived calliper.
- To provide continuous measurement of the cave-in rate while tripping / reaming.

These applications have yet to be fully proven. Due to the number of corrections and assumptions, and the labour intensive management of the cuttings catcher data, real time quantitative information cannot be relied upon, (i.*e., the artificial calliper*). Only real time qualitative trend information can be used to predict hole cleaning efficiency and stability. Further field trial experience is required to both develop and improve the cuttings catcher equipment and theory.

3.15.2 **General Hole Cleaning**

Removal of cuttings from the well bore is an essential part of the drilling operation. Efficient wellbore cleaning must be maintained in all wells. Failure to effectively transport the cuttings can result in several drilling problems including:

- Excessive overpull on trips.
- High rotary torque.
- Stuck pipe.
- Wellbore pack-off.
- Formation break down.
- Slower ROP.
- Lost Circulation.

The rig team have control over a number of parameters that assist hole cleaning, namely pumping hole cleaning pills, methods used to pull out of the hole, choice of reaming speeds, choice of ROP, flowrate, movement of string while circulating, etc. Of these the annular flowrate is important.

Hole cleaning is often more of an issue in a gauge hole than it is in an over gauge hole. When drilling a 17.5” hole using a gyp/ligno mud system with frequent dumping and diluting the diameter of the hole can be as much as 24 inches. If a 10” inch cuttings bed exists the BHA will pass this with only minimum extra drag. If a highly inhibitive mud system is being used for drilling shale in a 12.25” hole, the diameter of the hole is likely to be 12.25”. A 1.5” cuttings bed can cause severe overpull problems in this hole if it is not dealt with correctly.

All of these are potential problems for both near vertical (*less than 30 ° deviation*) and ERD wells. Generally, hole cleaning rarely presents a problem in near vertical wells. The problems listed above are common on highly deviated wells.

Successful hole cleaning relies upon integrating optimum mud properties with best drilling practices. When difficulties are encountered it is essential to understand the nature and causes of the problem. This allows options to be focused on determining the most appropriate actions.

3.15.3 General Factors Effecting Wellbore Cleaning

There is a large number of drilling parameters which influence the hole cleaning process. The driller has a direct control on some parameters, others are pre-determined by the constraints of the drilling operation.

3.15.3.1 *Cuttings Transport*

In holes inclined at **less than 30°**, cuttings are effectively suspended by the fluid shear and cuttings beds will not form.

- Conventional transport calculations based on vertical slip velocities are applicable to these wells.
- Generally for these shallow angled wells, annular velocity requirements are typically 20-30% in excess of vertical wells.

3.15.3.2 *Rheology*

The effect of mud rheology on hole cleaning depends on the annular flow regime.

- When laminar flow exists, increasing the mud viscosity will improve wellbore cleaning. (*This is particularly effective if the low shear rheology and YP/PV ratio are high*.)
- When turbulent flow exists, reducing the mud viscosity will help remove cuttings.

3.15.3.3 *Yield Stress*

This is a measure of the low shear properties of the mud. It is determined from the 6 and 3 rpm readings of a conventional Fann viscometer, [*YS=2x(Fann 6 - Fann 3)*].

Yield stress controls the size of cuttings which can be suspended by the flowing mud (*dynamic suspension*). The dynamic suspension will be affected by cuttings' size and mud density. In practice the optimum level required is best established based on field data and experience.

3.15.3.4 *Flow Rate*

The mud flow rate provides a lifting force on cuttings to carry them out of the well. In highly deviated wells, mud flow rate combined with mechanical agitation are the most important factors for hole cleaning. For vertical wells the rate of cuttings' removal increases with increasing annular velocity and/or increased rheological properties.

$$AV(ft/\min) = \frac{24.51 \times GPM}{\left(Holesize^2 - drillpipesize^2\right)}$$

3.15.3.5 *Hole Geometry*

Hole diameter has a very significant effect on annular velocity. Reducing hole diameter from 17½" to 16" will increase annular velocity by 18%.

3.15.3.6 *Mud Weight*

Mud weight influences hole cleaning by affecting the buoyancy of the drilled cuttings. As mud weight increases, the cuttings will tend to "float" out of the well making hole cleaning easier. In practice the mud weight window will be constrained by drilling factors other than hole cleaning (well bore stability, ECD, differential sticking, etc.).

3.15.3.7 *Cuttings Properties*

Hole cleaning is dependent upon both cuttings' size and density. Increasing size and density both tend to increase the cuttings' slip velocity. This makes transport more difficult. The effects of higher slip velocity can be combated by an appropriate increase in yield stress and mud gel. In extreme circumstances bit selection can be used to generate smaller cuttings and, hence, reduce slip velocity. However, if cuttings get ground up into fines they can be hard to remove from a deviated section of well bore.

3.15.3.8 *Rate of Penetration*

An increase in penetration rate results in a higher cuttings' concentration in the annulus. This will lead to a higher effective mud density in the annulus and higher circulating pressures, which may in turn limit flow rates.

3.15.3.9 *Rig Site Monitoring*

There are a number of rig-site indicators that should be used to monitor the hole condition and allow preventative action to be chosen. These should normally be examined for trends and sudden departures from the trend rather than absolute values.

- The shape and size of the cuttings coming over the shaker should be regularly monitored. Small rounded cuttings indicate that cuttings have been spending extended periods downhole being reground by the BHA. These are often evident coming over the bottom shaker screen. These fines can be of significant volume if regrinding of shale is occurring in an inhibitive mud system.
- The cuttings return rate at the shakers should also be measured and compared with the volume predicted from ROP. Simple devices are available to automate the measurement. However, it is difficult to measure the quantity of fines returning.
- Torque and drag can be used to determine whether cuttings beds are adding to the well bore friction. Simulations should be conducted in advance using Drill String Simulators. Deviations from the normal trend hook load, pressure, torque trend lines can be indicative of cuttings bed forming.
- Erratic signal in torque or stand pipe pressure can also be an early warning of cuttings beds.

3.15.4 Vertical and Near Vertical Wells

Rheology plays a very important role in transporting cuttings in vertical and near-vertical holes. Large diameter holes, in particular, cannot be cleaned by velocity alone. However, assuming that the mud has the correct rheology, hole cleaning on these wells is not normally a problem. The mud annular velocity is generally far greater than the cuttings' slip velocity and so the cuttings are carried out of the hole. To ensure that a low slip velocity is achieved, these wells are usually drilled with viscous, high yield point muds.

3.15.5 Hole Cleaning in Near Vertical Wells - Guidelines

1. Select mud properties to provide optimum hole cleaning whilst drilling. The specific properties will depend upon available pump rate. In all cases mud rheology should be maintained at a level that will reduce slip velocity to acceptable levels. Specific requirements for annular velocity compared with cuttings slip velocity can be obtained within hole cleaning software models.
2. Poor hole cleaning will result in high cuttings loading in the annulus. When circulation is stopped these cuttings can fall back and pack-off the BHA. When packing-off occurs this means the flow rate is too low or the well has not been circulated for sufficient time (*assuming that the above criteria for mud properties has been met).*
3. **Circulate the wellbore prior to tripping** -A single bottoms-up is rarely sufficient. The minimum recommended volume for vertical wells is 1.3 x bottoms-up (*1.5 for holes > $8^{1}/_{2}$"*). Monitor the shakers to ensure the cuttings return rate is reduced to an acceptable background level prior to commencing tripping.
4. Limit use of high viscosity pills to supplement hole cleaning. Rather adjust the properties of the active mud in circulation to provide optimum cleaning capacity. High weight pills should not be used in vertical wells.
5. For vertical holes **reciprocate rather than rotate the pipe** during circulation prior to tripping -- this helps remove cuttings from stagnant zones near the well bore wall.
6. Pulling through tight spots is permitted provided the pipe is free going down. Agree a maximum allowable overpull in advance with the Drilling Rep / Drilling Superintendent. Do not go immediately to the maximum overpull, but work up progressively, ensuring that the pipe is free to go down on every occasion.
7. Stop and circulate the hole clean if overpulls become excessive.
    a. **Avoid precautionary backreaming, only backream when essential.**
8. Understand the nature and causes of any problems encountered on tripping.

3.15.6 Mud Rheology

Experience has shown that good mud rheology is extremely important to hole cleaning when drilling a high angle well. Studies show that the effects of increasing rhelogy and annular flow regime are mutually dependent.

- In the laminar regime, increasing mud YP will improve hole cleaning. This is particularly effective if the YP/PV ratio is high. {*However, a more viscous mud has difficulty in lifting the cuttings off the bottom in a high angle well* }.
- In the turbulent regime, however, reducing mud viscosity will help in removing cuttings. {*However, reducing the viscosity will increase the likelihood of avalanching in a deviated well.*}

Therefore the mud rheology should be designed to avoid the transitional flow regime and the importance of mechanical agitation should be recognised. For hole sizes above 8½", the annular flow is laminar under most circumstances. Therefore it is desirable to specify a minimum YP/PV ratio. In practice the optimum level required is best established based on field data and experience.

3.15.7 Selection of Flow Regime

When correctly designed both laminar and turbulent flow regimes will effectively clean a deviated well. Increasing the YP of a fluid in laminar flow will improve hole cleaning of suspended cuttings as will a reduction of the YP of a fluid in turbulent flow decrease cuttings bed thickness. It is important that one or the other regime is selected and that the transition zone between the two is avoided, as it is the worst region in which to operate with intermediate mud properties. However, if laminar flow is chosen, string movement must be used to effectively lift the cuttings from the low side of the hole.

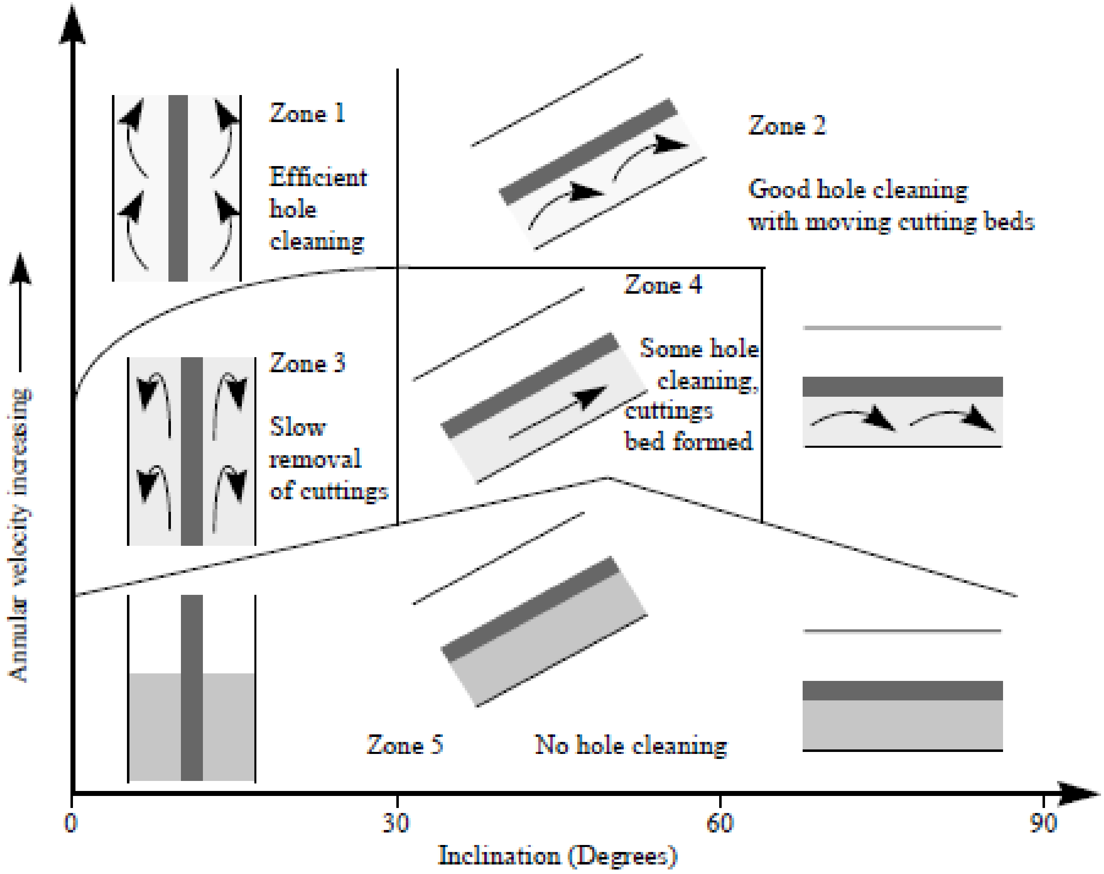
Generally, viscous fluids in laminar flow are preferred because:

- It is possible to achieve higher cleaning capacity (rheology factor).
- Viscous fluids give better transport in the near-vertical sections.
- Viscous mud has better suspension characteristics when circulation is stopped.
- It is difficult in practice to achieve "turbulent flow" except for small hole sizes.

Turbulent flow effectively prevents the formation of cuttings beds on the low side of highly deviated wells when the pumps are on. When the pumps are turned off the cuttings can rapidly fall to the low side of the hole and avalanche back down.

Turbulent regimes should not be used in friable, non competent formations. Subsequent wash-out of the rock will reduce annular velocities to a point where laminar flow will develop in a fluid with properties specifically designed for turbulence. Cuttings bed formation will inevitably follow. Effectively the same process can occur as the fluid, designed for turbulence in small diameter hole, enters larger diameters further up the hole. All fluids designed for turbulence must have, as a minimum, sufficient suspension characteristics and carrying capacity to clean these larger hole (casing) sizes.

Figure 12: Flow pattern of cuttings in wellbores of differing inclinations



3.15.7.1 ***Hole Cleaning Charts***

A series of Hole Cleaning Charts has been developed which can be used to determine the Critical Flow Rate for various hole sizes when drilling a deviated well. These charts, with examples, are included here as linked files.

3.15.7.2 ***Hydraulics***

Conventional drilling hydraulics rely upon optimising hydraulic horsepower or hydraulic impact at the bit. This requires approximately 60-70% of the system pressure loss to be dissipated at the bit. For ERD wells, where the flow rates for wellbore cleaning are higher, it is often necessary to reach a compromise and reduce the energy spent at the bit. This is achieved by selecting larger nozzle diameters. The distribution of pressure losses throughout the circulating system depends upon well geometry and fluid properties. In conventional drilling the annular pressure drop is generally <5% of the overall system loss (*this proportion increases dramatically for slim-hole configurations*). The annular pressure loss, whilst only a small fraction of the total loss is critical, for determining ECD.

3.15.7.3 ***Drill String Movement***

ROP is limited to prevent the percentage volume of cuttings increasing to a level where they have a detrimental effect on hole cleaning. A higher ROP requires a higher flow rate to clean the hole. It is a good practice to drill the hole with a steady ROP and select the required flow rate for hole cleaning accordingly. In cases where this cannot be achieved, the average ROP over a 30 m (*100 ft*) interval should be used to select the flow rate.

3.15.7.4 *Drill pipe Rotation / Reciprocation*

Experience has shown that *drill pipe rotation / reciprocation* is very effective in improving hole cleaning, in particular at high speeds (*e.g. above 150 rpm*). This is because the drill pipe rotation / reciprocation will mechanically agitate the cuttings bed and therefore help in removing cuttings. Discussions with the directional drilling company should be held regarding limitations of rotary speeds when using downhole motors. It is not advisable to reduce the flowrate while circulating bottoms up purely to prevent motor wear.

As flowrate alone cannot always remove a cuttings bed, reciprocation and rotating of the drill pipe are advised whenever the hole is being circulated clean. This action will dramatically increase the erosion of cuttings beds in highly deviated wells.

3.15.7.5 *Backreaming and Hole Cleaning*

Based on the same concept as restricting hole cleaning while drilling ahead, the rate of backreaming should be similarly restricted. Consider a drilling rate of 40 m/hr. If drilling a hole at this ROP then the volume of rock generated is 100% of the volume of the hole drilled .
When backreaming through a cuttings bed of 20% hole volume (*i.e. having a depth of approximately 20% of the hole diameter*) the rate of backreaming should be no more than five times the ROP used to drill that section originally. This will ensure that the same percentage cuttings in the annular fluid exist as when drilling at 40 m/hr (*assuming the same flowrate is used as when originally drilling*). This gives a maximum backreaming rate of 200m/hr. In terms of stands of drill pipe that is 6 - 7 stands per hour. If the maximum drilling ROP is less then the backreaming rate will also be less.

3.15.7.6 *Use of Larger Drill Pipe*

The pump pressure is often the limiting factor for achieving the required flow rate for hole cleaning. Therefore, it is often necessary to use larger than conventional 5" drill pipe such as 5½" or $6^5/_8$" in order to reduce the pump pressure required for a given flowrate. However, as use of a larger drill pipe size results in higher surface torque, overall length should be optimised.

3.15.7.7 *Circulation Prior to Connections or Tripping*

Before making a connection, the hole should be circulated at the normal flow rate to clear the cuttings from around the BHA. Depending upon the hole angle and the length of BHA, a circulation time of 5 to 10 min is often necessary.

Before *tripping out*, the hole should be circulated at the normal flow rate until the shakers are clean, whilst at the same time the drill pipe should be rotated at maximum speed / reciprocated. This may require up to 3 * bottom-ups, depending upon the hole angle and hole size. Table 9 lists the recommended number of calculated bottoms-ups prior to tripping.

Table 9: recommended number of calculated bottoms-ups prior to tripping

Hole Angle	$8^1/_2$"	$12^1/_4$"	$17^1/_2$"
0 - 10	1.3	1.3	1.5
10 - 30	1.4	1.4	1.7

3.15.7.8 *Wiper Trips (cures)*

A wiper trip or pumping-out-of-hole can be effective in managing hole cleaning problems once they have resulted. There may be required when difficulties are recognized during drilling or tripping out of the well. When problem a wiper trips may be deemed necessary on tripping back into the previous casing or when drilling a high angle section. This is particularly important if the actual flow rate is below or close to the critical rate. Once pumping out of the hole has commenced the pumps should be kept at drilling flowrate until tripping depth is reached, then at least bottoms up pumped to ensure the hole is clean. Once in the casing, if it is at a high angle, caution should be maintained until the inclination is less than 20 degrees. Prevention is preferred vs. a cure of time consuming wiper trips.

3.15.7.9 ***Trend Information***

It is advised that trend sheets should be used to log all hole cleaning parameters, i.e. flow rate, rpm, mud rheology versus depth and evidence of dirty hole on trips etc. This is useful for diagnosing subsequent problems and as offset information.

Trip procedures should be prepared in advance with guidance on tripping intervals, backreaming rates and maximum overpull. These procedures can be modified over the duration of the well to take into account specific well conditions.

By measuring the amount of cuttings over the shakers at regular intervals a cuttings return log can be established which will provide valuable information on trends in cuttings returns versus ROP.

3.15.7.10 ***Washed Out or enlarged wellbores***

In situations where out-of-gauge sections are common, every effort should be made to minimise the extent of wellbore enlargement. Factors such as mud design (*chemical*) and mud weight selection must be optimised to reduce the potential of a problem. Poorly consolidated formations can be prone to hydraulic and mechanical erosion. Bit hydraulics and drilling practices should be designed accordingly.

In areas where the formations are tectonically active the well bore sections are generally out of gauge. This causes a reduction in the annular velocity of the mud which together with the large *caving's (and hence higher slip velocity*), makes hole cleaning much more critical. Recommended ranges for rheological properties have been developed from well data analysis. Similar studies can be performed for other assets.

3.15.8 Hole Cleaning Charts

3.15.8.1 *Hole cleaning charts*

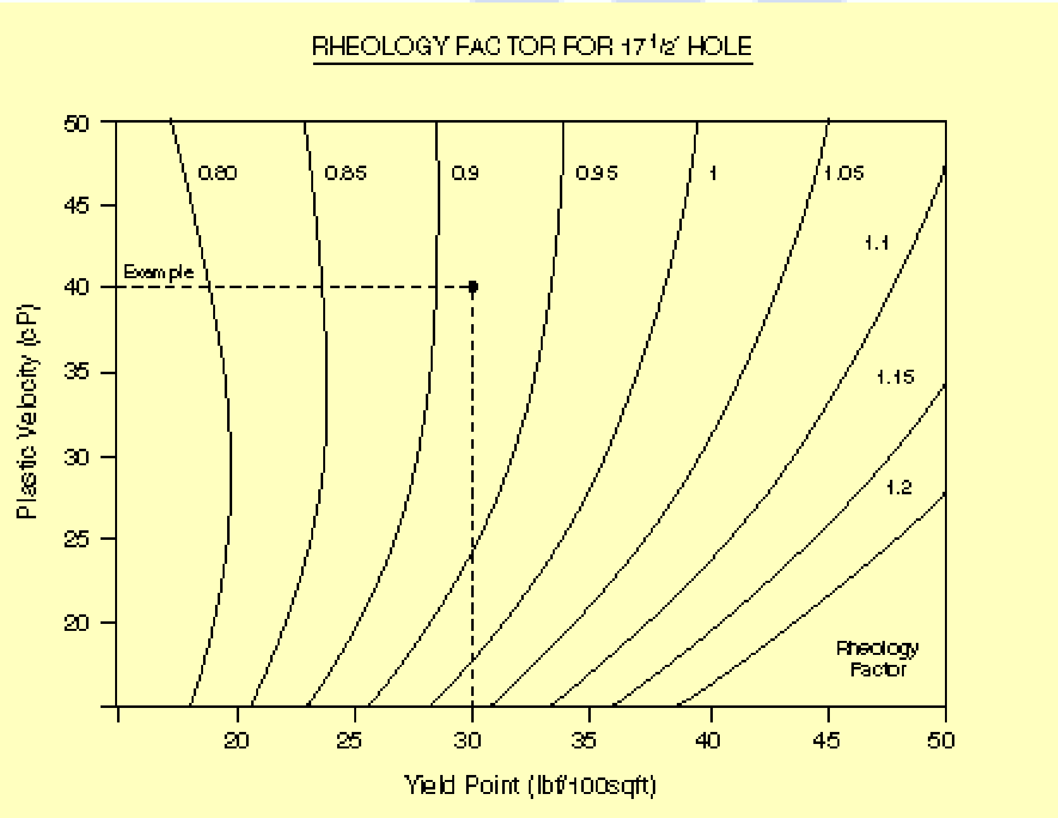
The following charts were derived based on the an operators hole cleaning model by assuming a set of drilling conditions which are considered typical of operations in the North Sea and Gulf of Mexico. Therefore, these charts should **not be used** in cases where the drilling conditions are significantly different from the assumed typical conditions.

Hole Size:	12¼”
Deviation:	60degrees
Mud Weight:	1.5sg
Plastic Viscosity:	30cp.
Yield Point:	25.lbs/100ft^2
Anticipated ROP:	20m/hr

The charts can be used to determine the flow rate requirement to clean the wellbore assuming.

1) The hole is in gauge
2) The hole is washed out to 13½"

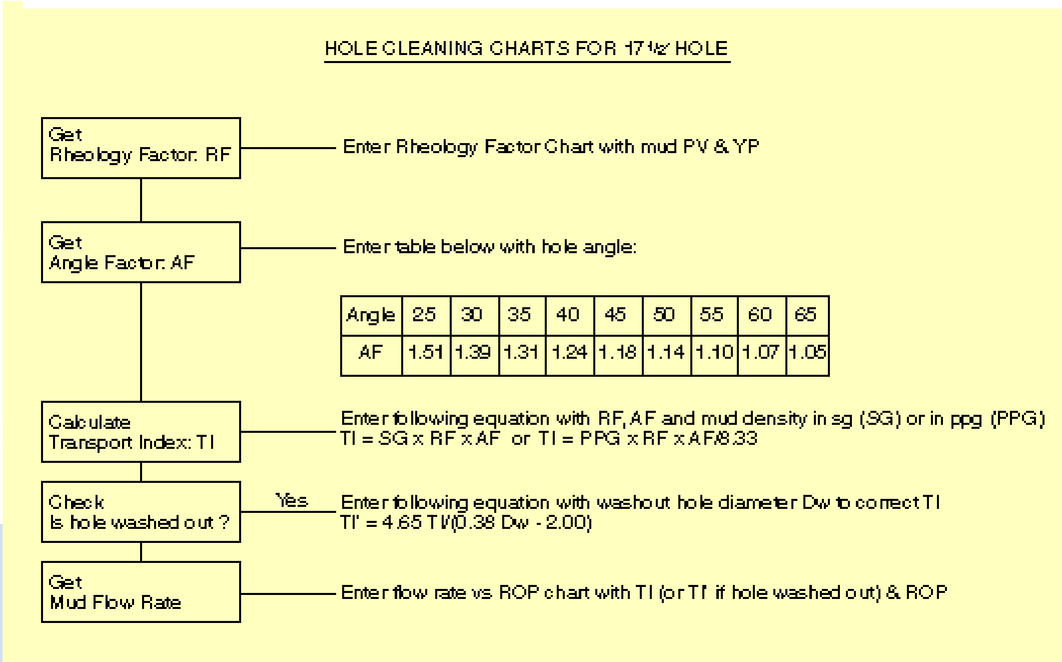
Figure 13: Rheology factor for a 17½” hole



3.15.8.2 *Gauge Hole*

- Find the Hole Cleaning Charts for **12¼" Hole**
- Enter the left hand chart with PV = 30 and YP = 25, read of the Rheology Factor RF = 0.99
- Use the Angle Factor (AF) table, read off AF = 1.07 for 60 degrees deviation
- Calculate the Transport Index, TI = 1.5 x 0.99 x 1.07 = 1.59
- As the hole is in gauge there is no need to correct TI
- Enter the right hand chart with ROP = 20m/hr and TI = 1.59; giving a required flow rate to clean the hole of 740gpm.

Figure 14: Hole cleaning chart example for 17½ wellbore.



Angle	25	30	35	40	45	50	55	60	65
AF	1.51	1.39	1.31	1.24	1.18	1.14	1.10	1.07	1.05

3.15.9 **Washed Out Hole**

- Required flow rate must be determined based on actual wellbore size – 13½"
- This is done by correcting the transport Index (TI) determined above
- Corrected TI' $= \dfrac{2.44 \times 1.59}{(0.38 \times 13.5 - 2.22)} = 1.33$
- Enter the right hand chart with ROP = 20m/hr and TI' = 1.33, giving a required flow rate to clean the enlarged hole of 910gpm.

3.16 Jar and Accelerators

There are two basic types of jar, mechanical and hydraulic. Hydraulic jars use a hydraulic fluid to delay the firing of the jar until the driller can apply the appropriate load to the string to give a high impact. The time delay is provided by hydraulic fluid being forced through a small port or series of jets. Hydraulic jar firing delay is dependent upon the combination of load and time. Mechanical jars have a preset load that causes the jar to trip. They are thus sensitive to load and not to time. It can be seen from these descriptions that the terms mechanical and hydraulic jar refers to the method of tripping the jar.

3.16.1 General Comments on the Use of Jars

Jars are frequently returned to the workshops marked 'failed' and subsequently test successfully. The main reason for this appears to be the inability to fire the jars, often in the down direction. Estimating the force required to fire jars, when the user is under pressure due to the stuck pipe situation, is not always performed correctly. This chapter gives some insight into how jars operate and how to choose the correct surface forces to fire the jars. There are a number of reasons a jar might fail to fire:

- Incorrect weight applied to fire jar - *one or more assumptions in calculation incorrect.*
- Pump open force exceeds compression force at jar (*no down jar action*).
- Stuck above the jar.
- Jar mechanism failed.
- Jar not cocked.
- Drag too high to allow sufficient force to be applied at the jar to fire it (*usually mechanical jars*).
- Well path is such that compression cannot be applied to the jar. (*no down jar action*).
- Jar is firing but cannot be felt at surface.
- Right hand torque is trapped in torque set-able mechanical jars.
- Not waiting long enough for the jar to fire - *see firing time vs. force charts for hydraulic jars.*

Correct use of jars and the correct application of jarring is critical to freeing stuck pipe. Applying the most appropriate jarring action is key to aiding or worsening the stuck situation. If while pulling out of the hole, the string becomes stuck the natural instinct of a driller is to jar up. This is, after all, the direction he is trying to move his BHA, i.e. out of the hole. However, if the string is packed off above a stabiliser, a likely cause of stuck pipe while pulling out of the hole, the act of jarring up may make the situation worse by compacting the pack-off.

Jarring should start in the opposite direction to that which got the string stuck

Another reason for the frequent inability to fire jars is the miscalculation of the forces required at surface in order to get the jar to fire. Although the calculations are relatively uncomplicated, in the heat of the problem on the drill floor small calculations can appear quite complex. It is often this type of situation that leads to the jars not firing.

3.16.2 **Forces Required to Fire Jars**

All jars have a firing force envelope for each direction they fire in. A dual acting *jar (one that can fire up and down*) will have both an up jar force envelope and a down jar force envelope.

The firing force envelope consists of two forces, one to cock the jar in preparation for firing, the second to fire the jar. A dual acting jar will therefore have two force envelopes, one for up jarring and one for down jarring.

The jar envelope forces can be considered at the jar or at the surface. The jar firing force envelope at the jar is known.

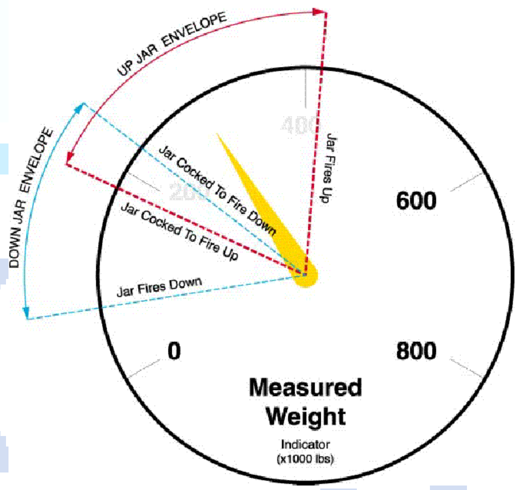
3.16.2.1 *Jar Firing Force Envelope*

It is the job of the rig team to estimate / observe the surface instruments in order to choose the surface firing force envelopes.

The forces that must be applied to the jar to cock and fire it when it is lying on a test bench are described by the jar force envelopes (*i.e. forces at the Jar*).

In the example above: To cock the jar to fire up, a compression force of approximately 5k lbs is required. This is to overcome internal friction. Once cocked the jar will fire once the force at the jar reaches 90k lbs.

Figure 15: Hydraulic Jar Action



To cock the jar to fire down, a tension of 5k lbs is required to overcome internal friction, once cocked the jar will fire down once 20k lbs compression is reached.

The fixed limits of 90k lbs and 20k lbs are typical of mechanical jars. When using a hydraulic jar, it will fire as long as the jar's internal friction is exceeded. The time taken to fire is inversely proportional to the force applied: the greater the force the shorter the waiting time. (*See hydraulic jar section for more information*).

We have only considered the forces at the jar so far. The driller only knows the force at surface and must estimate the force at the jars.

It is sometimes easy to see from the measured weight indicator when the jars are opening or closing. The measured weight indicator needle will stop moving for a few seconds while the string is still being moved up or down. It is a very good indicator that the axial neutral point is at the jar. It is often observed whilst drilling vertical wells but can be very difficult to observe in highly deviated, extended reach or horizontal wells.

If this neutral weight indicator is observed it is relatively easy to set surface jarring forces. The measured weight at which the neutral point is observed is recorded. The up trip force (*mechanical only*) is added to this value, together with any up drag.

Note: When stuck, any pull on the string results in an increase in drag over and above the normal up drag. The full amount of overpull applied at surface will not reach the jar. In deviated wells this must be compensated for by additional overpull.

If the pumps are running then the pump open force must also be subtracted from the firing force and added to the set-down weight used to cock the jars.

Note: The pump open force charts will be found in the manual for the jar being used. A copy of the current pump open force charts for the types of jars covered by this text is included after the description of each jar type.

Similarly the down trip force (*mechanical only*), the down drag and the pump open force are subtracted from the neutral point reading.

If the neutral point at the jars cannot be observed then the calculated neutral weight at the jars must be used.

3.16.2.2 *Pump Open Force*

The jar pump open force (*also called jar extension force*) is the effect of the difference in surface areas of the jar exposed to pressures on the out side and inside the jar. When a differential pressure exists between the inside of the jar and the outside of the jar it causes a force that opens the jar. Depending on the jar type the force acts on the cross-sectional area of the washpipe, or the washpipe and any floating pressure equalising piston exposed to the internal fluid of the jar. The effect on jarring can be considerable if for example 2000 psi is trapped inside the jar when the string is packed off below the jar. The pump open force chart for each type of jar discussed is included in these guidelines.

The pump open force acts to:

- **Assist firing the jar up**
- **Assists cocking the jar after firing down**
- **Opposes firing the jar down**
- **Opposes cocking the jar after firing up**

As an example we can look at a situation that happened recently in the North Sea.

Table 10: Example jarring forces calculation

Example Case	**k lbs**			**k lbs**
Up Trip Force (at jar)	90		Down Trip Force (at jar)	30
Up Cocking Force (at jar)	10		Down Cocking Force (at jar)	10
Down Weight (at surface)	120		Pump Open Force	34
Up Weight (at surface)	240			
BHA Weight Below Jars	50		Free Rotating Weight of string	200
Up and down cocking force = jar internal friction				
Apply at least	146	k lbs	at surface to cock jars for jarring up	
Apply at least	246	k lbs	at surface to jar up	
Apply at least	46	k lbs	at surface to cock jars for jarring down	
Apply at least	6	k lbs	at surface to jar down	

Gray areas are of less interest in this example

Having struggled out of the hole pumping and with indications of pack-offs the string finally packed off. Jarring commenced in a downward direction. There were 2000psi trapped in the string and the pack-off was below the dual acting hydraulic jar. The parameters were as shown at right: As can be seen with 2000psi trapped in the string a 34klbs pump open force resulted. Down jarring was attempted six times, each time the measured weight reading of 60klbs was held for 30seconds without any indication of the jar firing. Down jarring was aborted and up jarring commenced until the well was sidetracked.

The three main problems identified were:

1. Trapped pressure inside the string while trying to jar down.
2. Insufficient weight to allow down jarring (*even without the pump open force opposing this action*)
3. Insufficient time allowed for the jar to meter through its stroke.

For Calculation of jar forces see Jar Calculation Section

3.16.3 Jar Descriptions

3.16.3.1 *Weir Houston*

Weir Houston Hydra-Jars are dual acting hydraulic drilling jars. These jars fire up and down from a central "cocked" position. The time to fire is dependent upon the pull applied at the jar and the position of the jar in its cycle when the pull is applied. The minimum force at the jar required to stroke the jar up or down is dependent upon the jar's internal friction. The maximum force that can be applied to the jar is determined by two factors:

1. The maximum design pressure in the hydraulic fluid inside the jar gives rise to a maximum applied force when the jar is stroking.
2. Once the jar is fully open or fully closed the maximum applied force is determined by the steel strength of the jar.

There is no mechanical trigger or latch mechanism. Therefore the firing force is determined by whatever force the driller applies to the jar. However, the lesser the applied force the longer the jar takes to fire. This can be up to 7 minutes if the jar moves from fully open to fully closed. It can also be as little as a few seconds if the jar is only partially cocked then fired. Once jarring is established the average delay time will be 1 - 2 minutes. See figure for full details for delay time versus applied force at the jar.

These jars are subject to pump open forces acting on the cross-sectional area of the wash pipe. Pump open force is sometimes referred to as jar extension force.

Floating seals inside the jar keep the pressure of the internal fluid equal to the pressure of the fluid outside the jar, via ports to the annulus. Grease and or mud can be observed emerging from these ports when the jar is returned to surface. This is not an indication of a jar failure and is perfectly normal.

Details of the jars used in Northern North Sea cold conditions service (Deepwater Development Project).

17½"	:	9½" Weir Houston Hydra-Jar,	8" WH Accelerator
12¼"	:	8" Weir Houston Hydra-Jar,	8" WH Accelerator
8½"	:	8" Weir Houston Hydra-Jar,	8" WH Accelerator

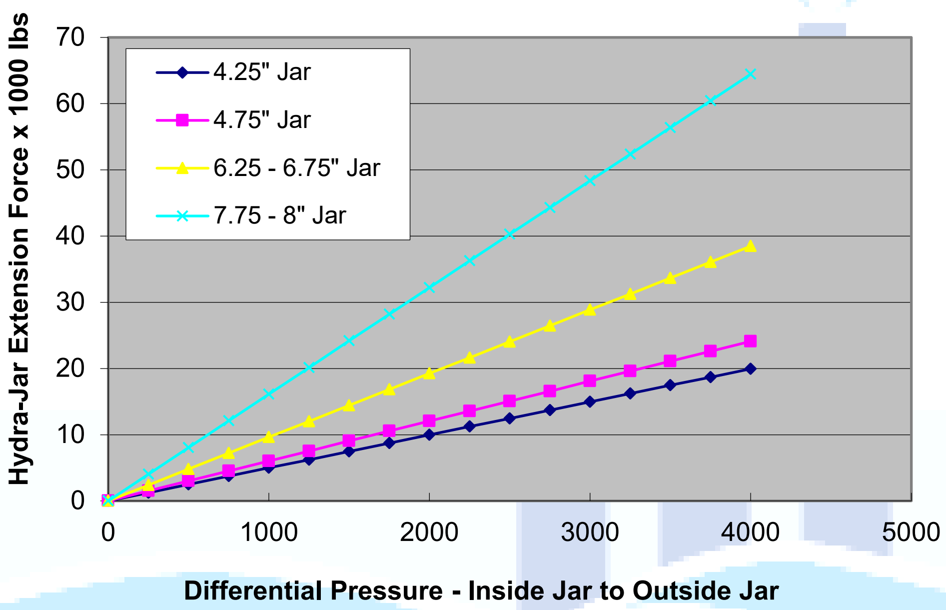
The jars for the top hole and 17½" are filled with very light oil and modified (*slicked metering ring*) to give a better response in the very cold environment. With this setup the "Time Delay Times vs. Load Graph Line" for 4¾" jars is used instead of the relevant one for the size of the jar.

The jars for the 12¼" and 8½" use regular oil and metering but include stand-off subs (*three spaced along the body*), to minimise differential sticking risk.

3.16.3.2 *Pump Open Force Information*

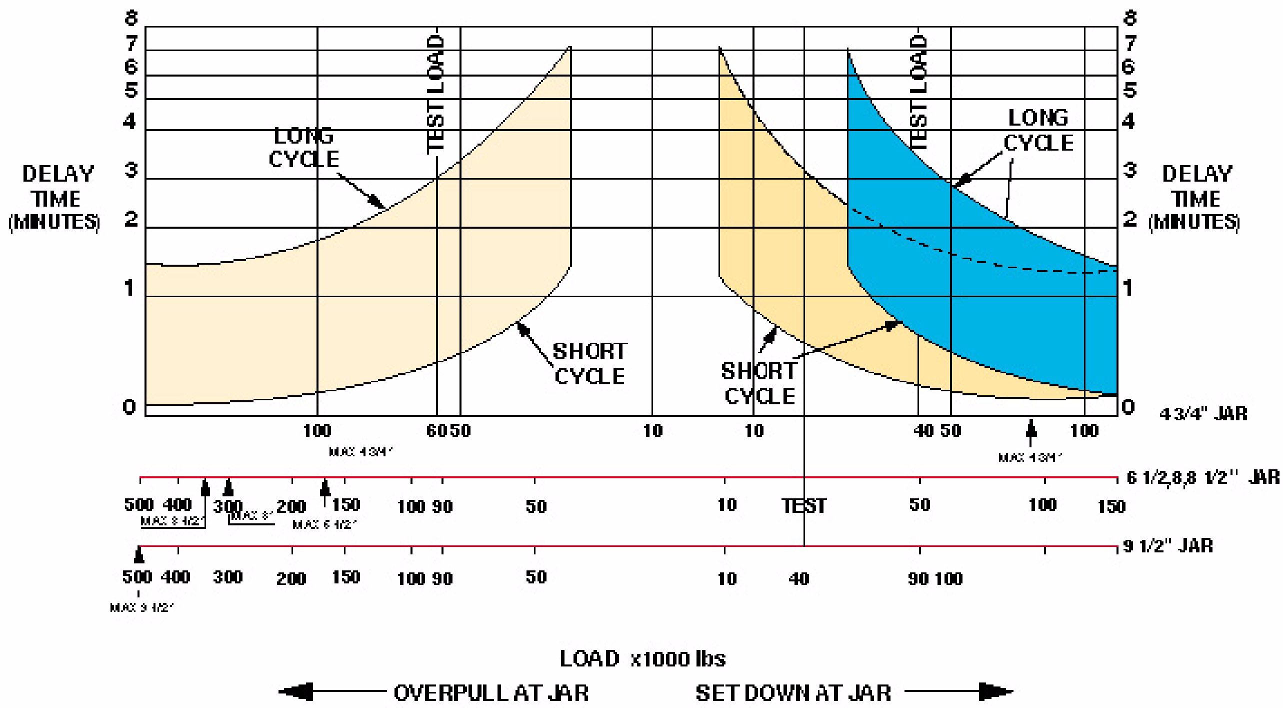
Figure 16: Pump Open force chart

WEIR-HOUSTON JAR -PUMP OPEN FORCE CHART



3.16.3.3 *Metering Time Information*

Figure 17: Metering time information



3.16.3.4 ***Tool Specification Summary***

Table 11: Tool specification summary

Tool OD	4¼"	4¾"	6¼"	6½"	7¾"	8"
Tool ID	2"	2¼"	2¾"	2¾"	3"	3"
Tool joint connection type	NC31	NC38	NC50	NC50	6⅝"Reg	6⅝"Reg
Max working load while jarring (lbs)	70000	80000	150000	155000	200000	250000
Tensile yield strength (lbs)	500000	575000	800000	865000	1300000	1480000
Torsional yield strength (ft.lbs)	35000	45000	75000	75000	150000	150000

3.16.4 **Bowen Jars**

Bowen hydraulic drilling jars are often rented by companies other than Bowen. Bowen (now NOV) do not rent hydraulic drilling jars from Aberdeen. They only sell them. In countries other than the UK Bowen hydraulic drilling jars may be used by some service and drilling companies.

Bowen hydraulic drilling jars are a dual acting combination tool. The hydraulic mechanism is only on the up jar action. The down jar is a friction mechanical system.

The metering action of the hydraulic mechanism is controlled by ports on an insert within a piston. This differs from other types which use metering jets. There are no details on the time delay of the Bowen hydraulic mechanism.

Figure 18: Bowen jars, Up Jar – Pump Open Force

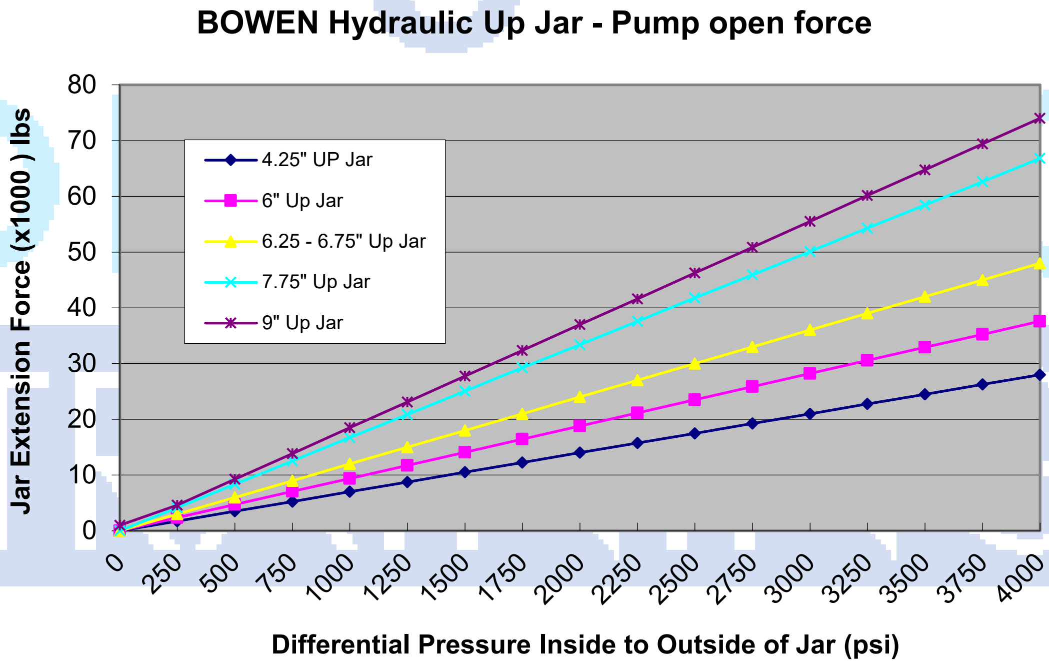
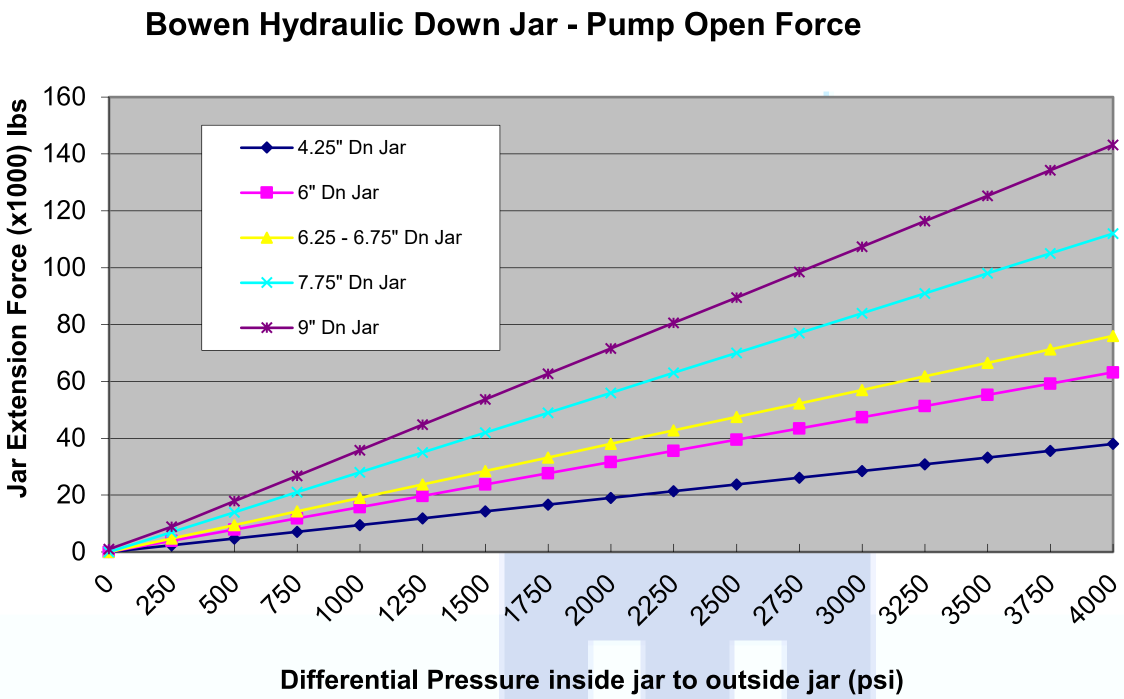


Figure 19: Down jar – Pump Open Force



3.16.4.1 ***Tool Specification Summary***

Table 12: Tool Specification Summary

Tool OD	4¼"	4¾"	6¼"	6½"	7¾"	8"
Tool ID	2"	2¼"	2¾"	2¾"	3"	3"
Tool joint connection type	NC31	NC38	NC50	NC50	6⅝"Reg	6⅝"Reg
Max working load while jarring (lbs)	70000	80000	150000	155000	200000	250000
Tensile yield strength (lbs)	500000	575000	800000	865000	1300000	1480000
Torsional yield strength (ft.lbs)	35000	45000	75000	75000	150000	150000

3.16.5 **Cougar & IPE**

The Cougar Drilling Jar (*DJ-6*) can be configured in three ways.

1. Mechanical bi-directional.
2. Combined mechanical down - mechanical/hydraulic up.
3. Hydraulic up only.

The mechanism used in each case is the same one.

The most complex, the combined mechanical down, mechanical/hydraulic up will be described here.

3.16.5.1 ***The Cougar mechanical latch mechanism***

The jar has a central array of pads attached to the inner mandrel that locate into a profile on the inside of the outer mandrel. These pads lock the inner and outer mandrel together until a preset force is reached. The pads then push together and allow the inner mandrel to slide inside the outer mandrel. This sliding stops when the hammer and anvil of the jar collide. The force required to unlatch the pads in the up and down directions are independent and can be set in the workshop. They are usually set at different values - the up setting higher than the down setting. These settings determine the jar tipping force required to fire the jars. When the jar is placed in its central position the latch re-engages into the profile and the jar is cocked ready to fire in either direction.

The hydraulic workings of the jar come into play on the up firing mechanism only. Once the mechanical latch has unlatched, a one way valve closes causing hydraulic fluid to be forced through a metering jet. As the size of the jet is small it controls the speed of movement of the inner mandrel up inside the outer mandrel. After several inches of metering a change in profile of the outer mandrel allows the hydraulic fluid to by-pass the metering jet. The inner mandrel is then free to move quickly up the outer mandrel and fire when the hammer and anvil collide.

There is no effect from the hydraulic mechanism when jarring down.

As with all hydraulic jar mechanisms reviewed so far, the time taken to meter through the hydraulic part of the stroke is dependent upon the force applied at the jar.

It should also be noted that the jar can be run upside down to give a mechanical up - mechanical/hydraulic down jar action.

If the hydraulic mechanism fails, the mechanical latch will still be functional and give both up and down jar action. The Cougar jar is not sensitive to torque other than normal torsional yield values given in the tables below.

Figure 20: Pump Open Force

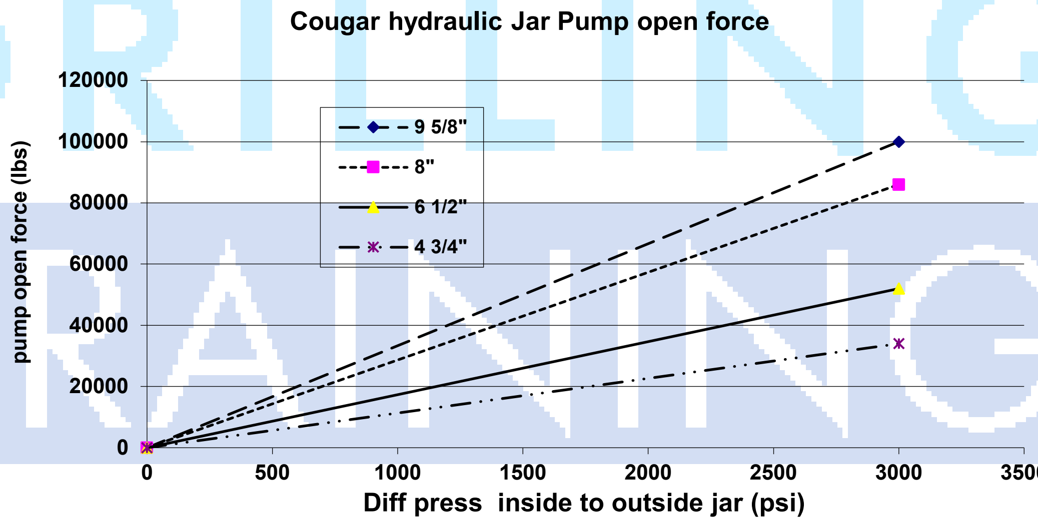
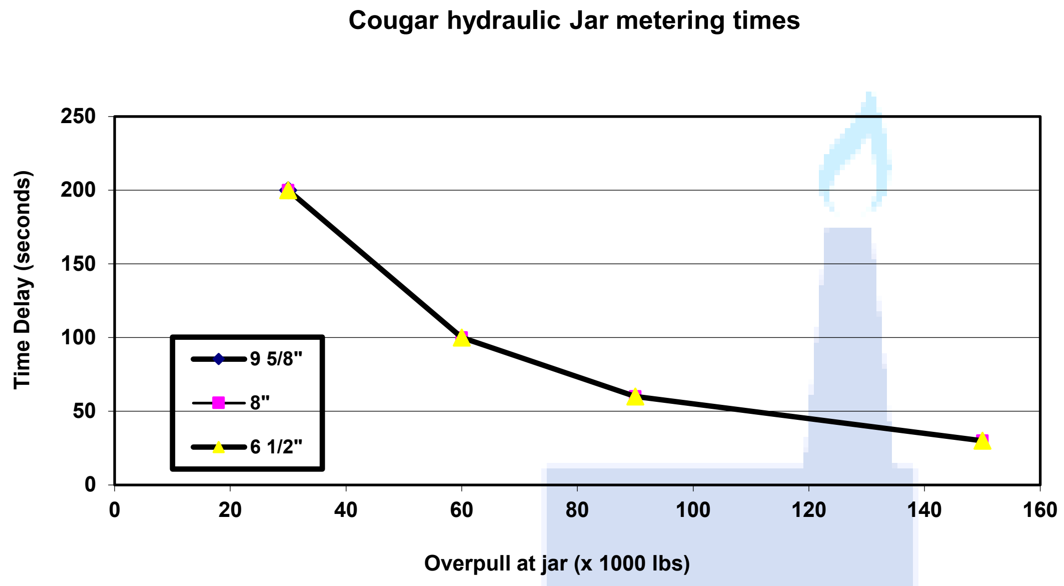


Figure 21: Jar Metering Times



3.16.5.2 ***Tool specification summary***

Table 13: Tool Specification Summary

Tool OD	4.75”	6.5”	8”	9.5”
Tool ID	2.25”	2.56”	2.75”	2”
Tool joint connection type	NC38	NC50	6.675”Reg	7.675”Reg
Max working load while jarring (lbs)	100000	180000	295000	410000
Tensile yield strength (lbs)	380000	700000	1500000	1500000
Torsional yield strength (ft.lbs)	30000	60000	100000	120000
Up latch firing force	30000	80000	80000	80000
Down latch firing force	30000	57000	57000	57000
Make-up torque ft.lbs	10000	30000	50000	60000

3.16.6 Dailey jars

There are two types of Dailey HDJ-100 jar: the HDJ-100 and the HDJ-100-BB. The BB stands for big bore and is a redesign of the original HDJ-100 to provide a larger through bore for some sizes of jar. If the ID of your drill string is critical, ensure you specify the BB type. The two types differ slightly in design. The jars described below are the BB type. These dual acting hydraulic jars are described below:

The Dailey hydraulic jar consists of an inner mandrel and an outer mandrel. The inner mandrel has two pistons that seal on the outer mandrel. Between the two pistons there is a hydraulic valve that is closed when the jar is cocked and in its central position. When the jar is being fired up the hydraulic fluid meters through a pair of metering jets which restrict the speed of movement of the inner mandrel through the outer mandrel. The lower section of the hydraulic valve connects with a profile on the outer mandrel and is prevented from moving with the inner mandrel. As the inner mandrel keeps moving through the outer mandrel under the force applied from surface the two halves of the hydraulic valve are forced apart, allowing hydraulic fluid to pass through ports and by-pass the metering jets. The inner mandrel then free, moves quickly through the outer mandrel until the hammer and anvil collide firing the jars.

The jar is cocked by placing it in its central position from where it can be re-fired in either direction. Jarring in both directions takes place in the same manner. On the older design HDJ-100 jar the valve is opened by a set of arms that connect onto a profile on the outer mandrel but the mechanism is very similar otherwise.

Figure 22: Jar Metering Times

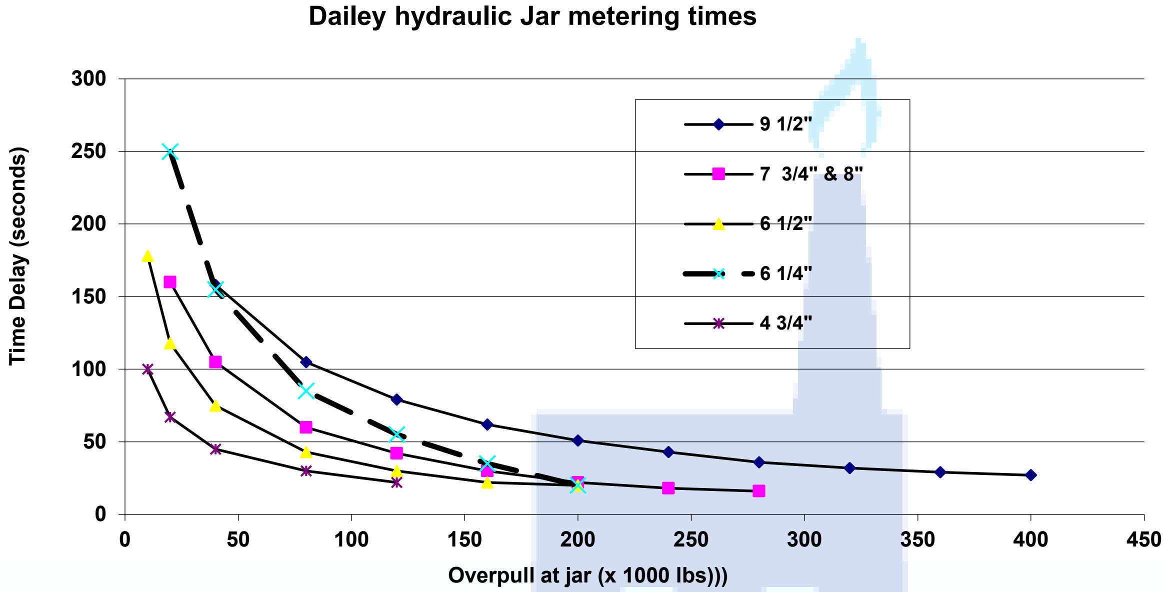
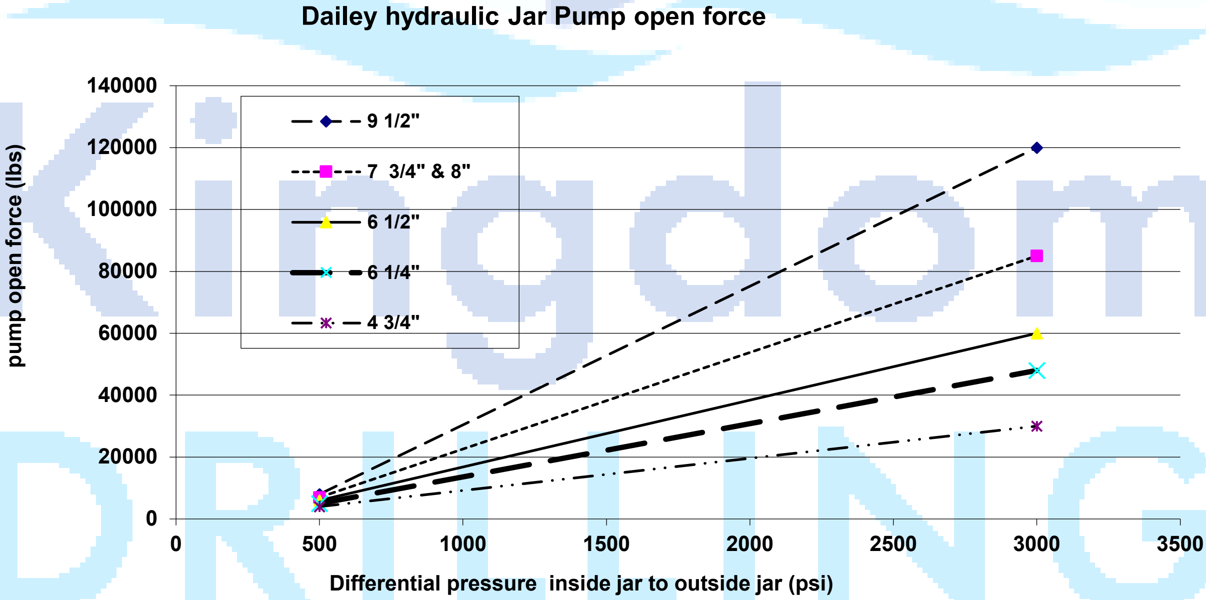


Figure 23: Jar Pump Open Force



3.16.6.1 *Tool specification summary*

Table 14: Tool specification summary

Jar type Original HDJ-100	**HD100**	**HD100**	**HD100**	**HD100**
Tool OD	4¼"	4¾"	6¼"	7¾"
Tool ID	2 1/8"	2 1/16"	2¼"	3"
Tool joint connection type	NC31	NC38	NC50	6⅝"Reg
Max working load while jarring (lbs)	55000	95000	200000	260000
Tensile yield strength (lbs)	325000	436000	832000	1600000
Torsional yield strength (ft.lbs)	15000	21200	49300	76400

Table 15: Tool specification summary

Jar type HDJ-100 Big Bore	**HD100BB**	**HD100BB**	**HD100BB**	**HD100BB**
Tool OD	4¾"	6½"	8"	9½"
Tool ID	2¼"	2¾"	3"	3
Tool joint connection type	NC38	NC50	6⅝"Reg	7⅝"Reg
Max working load while jarring (lbs)	85000	175000	300000	500000
Tensile yield strength (lbs)	500000	934000	1750000	2300000
Torsional yield strength (ft.lbs)	20000	56200	105000	160000

3.16.7 Handling of Small Drilling / Fishing Jars (Dailey)

3.16.7.1 *Delivery to Location*

1. The drilling/fishing jar will be delivered to the location with the mandrel in the closed position. Approximately a 1" gap will be present between the bottom of the box end of the mandrel and the top of the upper housing of the jar. This is a general design feature in some jars that prevents debris in the well bore fluid from being driven into the upper seals when the jar is re-cocked causing a loss of seal integrity.
2. If there is a larger gap or the mandrel appears to be in the open position, approximately 5-1/2" to 8-1/4" inches of mandrel exposed depending on jar size, contact the nearest jar representative. Check to see if there are any indications that the jar has been leaking and advise the jar company representative of this anomaly.
3. All service breaks on the jar body / housing connections are torqued at the Jar Contractor's service centre. It is NOT NECESSARY for the rig crew to tighten the body / housing connections before running the jar in to the hole or to break the connections when laying the jar down.

3.16.7.2 *Picking Up and Laying Down of Jars*

The small drilling / fishing jar is picked up and laid down in the same manner as any other jar:

1. Tie the pick up line around the middle of the jar and make sure the jar is balanced when hoisting the jar up to the rig floor.
2. DO NOT use the gap at the top of the jar as a tie on point when picking the jar up or when laying the jar down. Use a lifting sub.
3. If necessary, use a tailing rope to control the motion when the jar is being picked up or laid down
4. Use thread protectors while handling the jar, and do not allow the pin or box connections to be abused during handling. Damage to the connection will lead to:
    a. Improper makeup torque on the connection
    b. Galling of the threads
    c. Connection washout

3.16.7.3 *Stand Back Procedures for Drilling/Fishing Jars*

1. It is not recommended that drilling/fishing jars be racked back in the derrick when the string is out of the hole.
2. In fishing or drilling applications it is recommended that when the string is out of the hole, the jar should be removed from the string and laid down. Extreme cases where the operation does not permit this, the jar should be placed on top of the string in the closed position or open with a jar clamp in place.

3.16.7.4 *Routine Maintenance of Drilling/Fishing Jars in the String*

1. The drilling/fishing jar is a rugged downhole tool that requires very little maintenance while on the job
2. To ensure maximum jar performance, it is recommended that on every trip out of the hole the rig crew use the water hose to wash off the mandrel of the jar. The top of the upper housing where the mandrel goes through the upper seals should also be washed.
3. Unscrew the jar from the BHA at the pin end and insert the water hose into the ID of the pin and wash around the compensating piston. (*Except on Weir Houston Hydra jar, which do not have a compensating piston*).

3.16.8 Accelerator Description

The functions of a drilling accelerator can be summarised as follows:

- To compensate for the lack of stretch in a short string.
- To compensate for slow contraction of the drill string due to high hole drag.
- Act as a reflector to the shock wave travelling up the string from the jar blow.
- Intensify the jar blow.

  Drilling and fishing accelerators (*also called jar intensifiers*) are basically the same design. The Drilling equipment has an up-rated spline drive mechanism to enable the tool to withstand 300-500 rotating hours.

  The accelerator consists of an outer barrel and an inner mandrel. The inner mandrel slides in / out of the outer barrel. The two are connected by an interference fit between a piston chamber on the outer barrel and piston on the inner mandrel. The piston chamber contains a solid or fluid or gas that acts as a spring. When a force is applied to the accelerator the tool opens. The extension is dependent upon the applied force. When the extending force is released, the tool closes under the spring force of the fluid inside the piston chamber. Dual acting accelerators work in similarly with both the up jar and down jar.

3.16.9 Jar and Accelerator Positioning

Jar positioning programs do exist but all are configured to position the jars for maximum up jarring effect, which is not always the desired direction for jarring. To make a full analysis of optimum jar position many factors must be taken into account. However, this is not normally done for drilling operations. Usually the jars are run in a position determined by field / personal experience or company policy.

There are a number of issues that should be considered when positioning jars in a drill string.

- Likely places for sticking to occur.
- Most likely jarring direction required.
- Well bore contact / differential sticking risk.
- Position of the Axial neutral point when drilling with maximum WOB.
- Depth of hole section.
- Drag in hole section.
- Minimum allowable measured weight for plastic buckling when not rotating.

3.16.9.1 *Guidelines for Use of Jars in Vertical Wells*

In vertical wells the jar should be placed such that:

1. They are above the buckling neutral point even when maximum WOB is applied.
2. They are at least two Drill Collars above the jars.
3. They have differential sticking prevention subs fitted, if differential sticking is a risk.
4. No stabilisers should be placed above the jars.
5. Use Accelerators in shallow hole section. (*Check that it will be possible to cock and fire the jar before running them*)

3.16.9.2 ***Guidelines for Use of Jars in Deviated & Horizontal Wells***

1. Do not run the jars if they are buckled. *(This is easily said, but complicated to work out. Jars should not be run below the buckling neutral point in 45 degree wells. In horizontal wells the jars can be run in the 90 degree section without much chance of them ever being buckled.)* The area in the string to avoid placing jars is the pressure area neutral point. This is the point in the string where the tension in the steel is zero and is always above the buckling neutral point.
2. If using two jars or two jars and an accelerator ensure the driller is fully aware of how to use this system.
3. Use jars with differential sticking prevention subs if differential sticking is a risk.
4. It is important to calculate the measured weight readings at which the jar will cock and fire. The drag in the hole may prevent the driller from seeing the jars open and close on his weight indicator gauge.
5. In horizontal well drilling, a common problem is the inability to get sufficient force to a horizontally placed jar to fire it down.