1 DROPPING THE DRILLSTRING

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

Situations that may require the drillstring to be released include:

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

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

1.1 RECOMMENDED PRACTICE FOR DROPPING DRILLSTRING

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

1.2 RECOMMENDED PRACTICE FOR DROPPING DRILL COLLARS

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

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

2 SHEARING THE DRILLSTRING

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

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

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

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

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

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

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

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

2.1 RECOMMENDED PRACTICE

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

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

3 DISCONNECTING LMRP

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

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

3.1 BULLHEAD AND EMERGENCY DISCONNECT

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

3.2 EMERGENCY DISCONNECT (NO BULLHEAD)

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

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

4 RECONNECTION FOLLOWING EMERGENCY DISCONNECT

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

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

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

5 BLOWOUT/UNDERGROUND BLOWOUT

Contingency planning must be prepared on the following basis:

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

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

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

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

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

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

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

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

5.1 FLOW TO A FRACTURE ABOVE A HIGH PRESSURE ZONE

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

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

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

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

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

5.3 RECOGNIZING AN UNDERGROUND FLOW

Indicators of underground flow

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

5.4 KILL METHODS

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

5.4.1 FLOW TO A FRACTURE ABOVE A HIGH PRESSURE ZONE

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

A. Heavy Pill

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

B. Barite Plugs

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

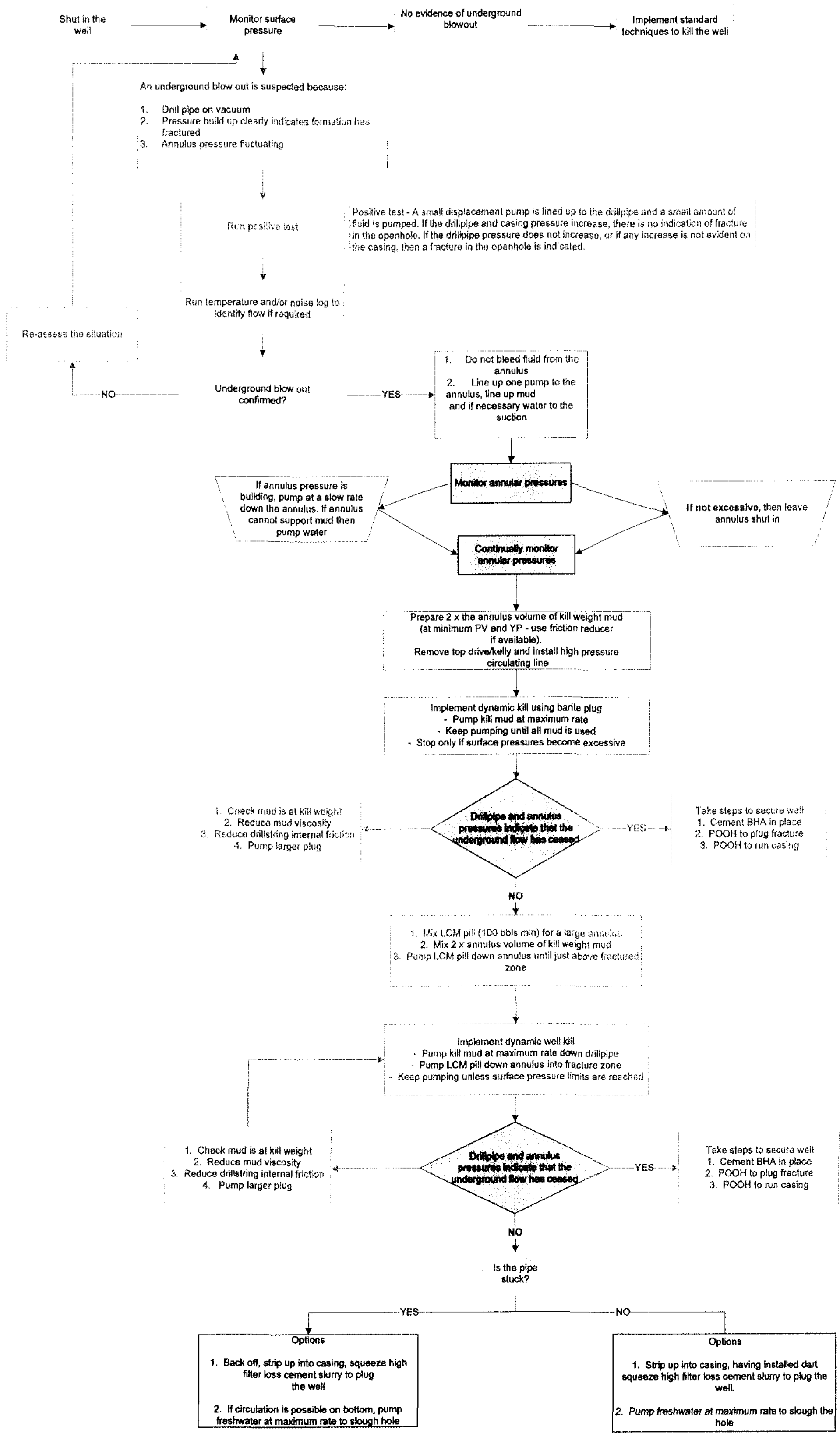

Figure 7.2.2, Decision Analysis for Flow to a Fracture or Loss Zone Below a High Pressure Zone