8.3.4 Slurry Volume and Slurry

If room on the rig permits, in areas with possible shallow gas, a reserve supply of drilling fluid weighted 1 to 2 lb/gal above the expected need is often carried in reserve, and is immediately pumped in the well if a shallow gas kick occurs. This may be effective in maintaining well control. If the drilling fluid supply is exhausted and conditions are such that the attempt can be made safely, a barite-water slurry of 18-20 lb/gal density may be pumped using chemicals to increase settling rate as described for barite plugs (refer to 13.4). This procedure serves to increase the hydrostatic pressure and settles the barite to form a plug. For more information on diverters and shallow gas flows, refer to 4.14, 7.3 and 7.3.1 as well as the references to API RP 64 and API RP 53 listed in 8.2.

8.4 DIVERTER STRIPPING OPERATIONS

Diverters should permit stripping pipe into the hole while diverting well flow. Inflation type diverters permit such stripping. Stripping life of this type diverter is maximized by use of minimum inflation pressure and by having a suitable accumulator of at least five-gallon capacity in the closing line near the diverter. This accumulator will reduce pressure surges when tool joints pass through the closing element. Closing time of such diverters is decreased with increasing closing pressure but, if stripping pipe through the diverter is required, closing pressure should be reduced to the minimum required to effect a seal.

For more information on stripping, see 12.8 entitled Stripping Operations.

9 Control Procedures—Surface Bops

9.1 PRE-KICK PLANNING

Prior to taking a kick, consider what action to take should a kick occur. A plan should be designed and implemented by the rig supervisor, utilizing the equipment and personnel available. This varies from rig to rig and for various operations, i.e., drilling, workover, tripping, etc. Some preliminary tasks must be performed to assure that all equipment is functional and the crew is aware of its duties in the program. The following outline details the recommended minimum pre-kick planning.

9.1.1 Supervision

1. Plan—Prepare detailed plan noting equipment limitations, casing setting depths, fracture gradients, expected hazards, maximum fluid density, and pressure that may be encountered. The plan should contain duty stations and functions for each member of the crew involved in the well control program.
2. Communications—Post the plan and discuss each function with personnel concerned.
3. Practice—Drills enhance crew response and assure that necessary safety devices are available and functioning.
4. Pre-recorded Information—Prior to drilling out the casing shoe, and daily while drilling or after a significant change in the circulating system pressure, the operator's representative should fill-in the pre-recorded information as shown on the applicable well control worksheets (refer to Appendix B):

   a. Record pertinent casing data-For combination casing strings, define the weight, grade, and internal yield strength of the uppermost section.
   b. Mechanical pressure limit-This is the safe working pressure of the surface BOP equipment, wellhead, and casing string.
   c. Casing pressure to cause fracture based on present drilling fluid density-This pressure may be calculated using either estimated or measured fracture drilling fluid density (refer to Notes 1A and 1B on the well control worksheets, Appendix B). If formation leak-off pressure is measured, use this pressure to determine the fracture drilling fluid density (refer to Note 1A on the well control worksheets, Appendix B) and to calculate the fracture pressure (refer to Note 1B on the well control worksheets, Appendix B).
   d. Approved maximum allowable casing pressures-The operator's representative should define the maximum allowable casing pressures for initial closure and the entire well control operation, select the contingency plan (refer to Paragraph 7.4.5) in the event maximum allowable casing pressure will be exceeded, and sign the well control worksheet.
   e. Normal circulating pressure and kill pressure data-The driller should record the normal circulating pressure and pump rate data; and, measure and record the kill pressure and pump rate data on the daily drilling report form.
   f. Calculate the pump rate (barrels per minute); enter it on the kill pressure and rate table; and obtain the drill pipe capacity in barrels per ft .
   g. The operator's representative should pre-select the shut-in method to be used by checking the appropriate box in the immediate action section of the suggested well control worksheet (refer to Appendix B).
   h. The operator's representative should also pre-select the trip margin for use in calculating the required drilling fluid density by completing the appropriate portion of the equation for calculating "Required Drilling Fluid Density" on the well control worksheets (refer to Appendix B).

9.1.2 Equipment Inspection and Test Schedule

1. BOPs and well control equipment should be inspected and tested in accordance with Section 17 (Surface BOPs) and Section 18 (Subsea BOPs) of API RP 53, *Recommended Practice for Blowout Prevention Equipment Systems for Drilling Wells* (reader should check for the latest edition).
2. Warning Devices—Inspect hourly and maintain operational (pit level recorders, flow indicators, gas detectors, lights, horns, etc.).
3. Drilling Fluid System—The primary well control system must be maintained continuously, with sufficient inventory of materials to handle, within reason, any unexpected well flow or lost circulation condition.

9.2 WELL CONTROL PROCEDURES

The following procedures assume that pre-kick planning is complete and a kick is suspected with the bit on, or near, bottom. This is generally the most desirable position for well control operations.

9.2.1 Suspected Kick

1. Stop drilling (or other operation) and position the pipe for the BOPs while sounding the alarm. (Note: Be aware of where tool joints are positioned in the BOPs.)
2. Shutdown the drilling fluid pump(s).
3. Check the well for flow.

9.2.2 Immediate Action When a Kick Occurs

1. When a kick occurs, stop drilling (or other operation), position the pipe for the BOPs while sounding the alarm, and stop the pump(s).
2. Chose 2(a) or 2(b) below:
   2(a) If the "soft shut-in procedure" has been selected: open the choke line; close the BOP, and close the choke (refer to 4.9.1).
   2(b) If the "hard shut-in procedure" has been selected: close the BOP and open the choke line with the choke or adjacent high-pressure valve closed (refer to 4.9.2).
3. Observe the casing pressure. If the casing pressure will exceed maximum allowed, follow the pre-selected contingency plan (refer to 7.4.5).
4. After closure, check for trapped pressure (refer to 9.5.1).
5. Allow closed-in pressures to stabilize and record the drill pipe and casing pressures.
6. If part of the approved well control plan, initiate pipe movement. Note: This action should be viewed with caution. Stuck pipe may be a minor problem compared with worn or leaking sealing elements during a well kick.
7. Determine the kick volume.
8. Calculate the drilling fluid density required to kill the kick (refer to 9.5.2).
9. Initiate the approved well kill method.
10. Check rig crew duties and stations.
11. Review and update pump output and hole volume data and complete the suggested well control worksheet (refer to Appendix B).
12. Adjust pit volume to allow for kick fluids volume and/or barite addition.
13. Check pressures on all annuli of the well.

9.2.3 Circulating Out Using the Driller's Method

This procedure dictates that the invading fluid (flow) be circulated out before increasing the drilling fluid density. Constant drill pipe pressure control is required throughout the initial circulation (refer to 4.10.2 and its subparagraphs).

1. Open the choke while bringing the pump to the kill-rate (refer to 9.5.3). Increase the pump rate slowly while holding the casing pressure at its initial closed-in value by adjusting choke.
2. When the kill-rate is reached, the observed drill pipe pressure should be equal to the calculated initial circulating pressure. If not, investigate cause (refer to 9.5.4). If no cause is evident, use the observed drill pipe pressure.
3. Continue to pump drilling fluid of the original density at the kill-rate, maintaining the drill pipe pressure constant by adjusting the choke. Continue to pump until the well is free of invading fluids.
4. Stop the pump while holding the casing pressure constant. The closed-in drill pipe and casing pressures should be equal and approximately the same as the initial closed-in drill pipe pressure. If not, circulate additional drilling fluid as in step 3 until the well is free of invading fluids.
5. Increase the drilling fluid density in the suction pit to the density required to kill the well. Monitor drill pipe and casing pressures. Percolation of gas causes shut-in drill pipe and casing pressures to increase. If this occurs repeat steps 4 and 5.
6. Circulate heavy drilling fluid, establishing circulation by bringing the pumps up to speed while holding the casing pressure constant at the value observed in the step 3 procedure plus any desired safety factor. Hold the pump rate constant at the kill-rate. Maintain casing pressure constant by adjusting the choke until the drill pipe is displaced.
7. When the drill string has been displaced with heavy drilling fluid, observe the drill pipe pressure.
8. Continue to circulate at a constant rate holding the drill pipe pressure constant at the pressure observed in step 7 by adjusting the choke. When the heavy drilling fluid reaches the surface, the casing pressure should approach zero.

9. Simultaneously close the choke and stop the pump. The closed-in drill pipe and casing pressure should be zero.
10. If the closed-in pressures are not zero, check the well for flow. If the well will flow, repeat the aforesaid operations beginning with step 5 and recalculate the drilling fluid density required to kill the well on the basis of the observed shut-in pressure.
11. If shut-in pressures in step 9 are zero and well will not flow, prepare to open the preventers. Caution: If, for some reason, more than one preventer is closed, pressure may be trapped between the closed preventers.
12. Open preventers and resume operations.

9.2.4 Wait and Weight Method

The well is closed-in on the kick; the drilling fluid density is increased in the pits as required; then the kick is circulated out with the weighted fluid (refer to 4.10.3 and its subparagraphs).

1. Mix kill fluid while maintaining constant drill pipe pressure by bleeding the annulus. Note how long it takes to mix and at what rate the equipment can continue to mix to the proper drilling fluid density. This gives a guide to selection of proper kill or displacement rate. To avoid shutdown, do not displace at a rate exceeding mixing rate (refer to Appendix B).
2. While mixing kill fluid, review and update pump output volume data and complete the suggested well control worksheet (refer to Appendix B).
3. Open and adjust the choke to hold casing pressure constant at its present closed-in value while bringing the pump up (slowly, if possible) to the kill-rate. Hold the kill-rate. At this time, the observed drill pipe pressure should be equal to the calculated value for initial circulating pressure. If they are approximately equal, then add or subtract the difference to/from the drill pipe schedule. If they widely differ, then use the observed drill pipe pressure as the initial circulating pressure and re-calculate the drill pipe schedule.
4. If the circulating pressure is correct, displace drill pipe at a constant pump rate in accordance with the pumping schedule on the well control worksheet. Maintain drill pipe pressure as per schedule by adjusting the choke.
5. Maintain constant pump rate and drilling fluid density. After the kill fluid reaches the bit, vary the backpressure on the annulus with the choke to maintain the drill pipe pressure constant at the final circulating pressure. Continue this operation until kill fluid is circulated. The variation in backpressure and pit volume during this circulation is a function of the amount and type (gas, water, or oil) of kick.
6. Continue pumping until kill fluid is circulated to the surface. Then stop the pump and shut-in the well. If sufficient kill fluid density was used during this circulation, the pressure should be zero.
7. If pressures are not zero, repeat operations in steps 1 through 6, with drilling fluid density adjustments.
8. If shut-in pressures in step 6 are zero, check well for flow before opening preventers. Caution: If, for some reason, more than one preventer is closed, pressure may be trapped between the closed preventers.
9. Open preventers and resume operations.

9.2.5 Concurrent Method

This procedure permits resuming well circulation and beginning weight-up operations immediately after well closure and pressure stabilization (refer to 4.10.4 and Figure 4.16).

1. Review and update pump output and hole volume data and complete the suggested well control worksheet (refer to Appendix B).
2. Open choke while bringing the pump up to kill-rate—Increase pump rate slowly, if possible. Adjust the choke to hold casing pressure constant at the initial closed-in casing pressure while bringing the pump up to kill-rate. Hold the kill-rate. At this time, the observed drill pipe pressure should be equal to the calculated value for initial circulating pressure. If they are approximately equal, use the choke to adjust the observed drill pipe pressure to the calculated pressure. If the two pressures are widely divergent, close-in the well and consider alternatives (refer to 9.6.4).
3. Start increasing the drilling fluid density—Record time and strokes when each drilling fluid density change occurs in the suction pit. A more even drilling fluid density is produced if auxiliary circulation is maintained between two pits.
4. Prepare a drill pipe pressure schedule so that the drill pipe pressure may be reduced (refer to 4.10.4) as the hydrostatic pressure inside the drill string increases due to heavier drilling fluid being pumped to the bit. More than one circulation may be necessary before the required drilling fluid density is attained.
5. Hold drill pipe pressure per prepared schedule—When the required drilling fluid density reaches the bit, drill pipe pressure should be held constant until the required drilling fluid density reaches the surface.

9.3 DRILL STRING OFF-BOTTOM

If the bit is off-bottom any significant distance, a drill pipe safety valve and inside BOP should be installed and the pipe stripped back to bottom (refer to 12.8). Well control operations with the bit off-bottom a significant distance offer less chance of achieving hydrostatic control of formation pressure. If it is impractical to strip back to the bottom, refer to procedures covered in Sections 12 and 13.

9.4 HIGH-ANGLE AND HORIZONTAL WELL BORES

The techniques used in conventional well control can apply to high-angle or horizontal wells. The high angles and small hole sizes require some additional considerations and precautions.

9.4.1 Kicks and Kick Detection

Compared to a vertical well bore, the characteristics of a kick in a high-angle or horizontal well include:

- Potential kick intensity can be high due to the long, high-angle section that may be through the kicking formation.
- ECD is relatively high due to small hole size and high measured depth.
- Kick detection can be complicated in a high-angle or horizontal well bore; pit gain and monitoring for drilling fluid flow are extremely important.
- Gas migration will occur relatively slowly in the high-angle well bore and may not occur at all in the horizontal portion of the well bore.

9.4.2 Well Control

Once a kick is detected, conventional close-in and well kill methods are effective. The hard close-in procedure is recommended to minimize kick influx due to the potential high productivity of the horizontal or high-angle formation. Some factors to consider after shut-in include:

9.4.2.1 Zero shut-in pressures do not mean a kick has not occurred. A positive pit gain may indicate a kick that is still in the high-angle or horizontal hole section.

9.4.2.2 Shut-in casing and shut-in drill pipe pressures will be very close due to little or no reduction in the annular hydrostatic pressure in high-angle or horizontal well bores.

9.4.2.3 Determining influx fluid type based on shut-in pressures and pit gain are not valid with high-angle/horizontal sections. However, increasing casing pressure indicates a gas kick expanding above the horizontal section.

9.4.2.4 The pump schedule for displacing the drill string with kill weight fluid is more complex due to the horizontal section.

9.5 REFERENCE NOTES FOR SECTION 9

9.5.1 Trapped Pressure

Trapped pressure in the case where a well with a kick is shut-in and the bottomhole pressure is above the reservoir pressure. For example, when the choke is closed before the pump is shut down, or gas migration occurs in a shut-in well (refer to 10.2.2 for trapped gas below subsea BOPs). It is good practice to check for trapped pressure after each well shut-in. The recommended check consists of bleeding the annulus slowly through a manual adjustable choke to detect any decrease in drill pipe pressure. The maximum volume bled should be limited to one barrel or less (much less in cases where the annular volume is relatively small). If drill pipe pressure does not decrease, pressure was not trapped.

9.5.2 Required Drilling Fluid Density Calculations

Required drilling fluid density is calculated using the initial static, shut-in drill pipe pressure. The equation is:

$$\text{Required drilling fluid density (lb/gal)} = \frac{\text{Closed-in drill pipe pressure (psi)}}{\text{Depth } (TVD)\text{, ft} \times 0.052} + $$
$$\text{Present drilling fluid density (lb/ gal) in the drill pipe (and trip margin where appropriate)}$$

Prior to mixing kill fluid, the pit volume should be adjusted to allow for gas expansion and barite addition anticipated during the kill circulation.

9.5.3 Kill-rate

Rig equipment may be the primary factor in selecting a kill rate for the well (refer to 4.8.5 for a description of kill-rate and 4.13 for information on subsea choke lines, another factor affecting kill-rate selection). A rate should be selected which will eliminate interruptions. Some of the considerations are:

a. Drilling fluid mixing capabilities, i.e., displacement rate should not exceed the mixing rate;
b. Surface fluid handling equipment, e.g., the mud-gas separator;
c. Minimum pump speeds (pump crippling may be required);
d. Pump pressure limitations;
e. Choke line friction; and
f. Choke-manipulation delays (human factors). Lower kill-rates should be selected to minimize interruptions.

9.5.4 Initial Circulating Pressure

In the event the observed initial drill pipe circulating pressure does not equal or approximate the calculated value, the well should be closed-in and the reasons for the wide divergence determined. This divergence may be caused by any of several factors including, but not limited to:

1. Calculation mistake,
2. Washout,
3. Pump failure,
4. Plugged bit nozzle or hole pack-off,
5. Gas cut drilling fluid in the pump suction,

6. Erroneous gauges, and
7. Changes in mud properties.

Recommendations for remedial actions for several of the factors listed above are covered in Section 12.

10 Well Control Procedures for Subsea BOPs

10.1 GENERAL

The procedures used to control wells equipped with subsea blowout prevention equipment are essentially the same as for those with surface control. There are, however, several additional factors, which must be taken into consideration. The purpose of this Section is to discuss these factors and show how they can be taken into consideration in applying the procedures recommended in Section 9, "Well Control Procedures—Surface BOPs."

10.2 ADDITIONAL CAUSES OF KICKS UNIQUE TO SUBSEA OPERATIONS

10.2.1 Loss of Integrity in the Marine Riser

Well bore hydrostatic pressure is a function of the height and density of the drilling fluid column from the flow line to the depth of interest. If a riser fails, leaks, or becomes disconnected, the drilling fluid gradient in the riser is lost and replaced by a seawater gradient (approximately 0.445 psi/ft-8.56 lb/gal) from the point of failure to sea level. The loss of well bore hydrostatic pressure associated with this situation can sometimes be sufficient to allow a well to flow. The first response should be to close the BOPs. In some situations, the drilling fluid density may be sufficient to compensate for the loss of hydrostatic pressure. If not, the loss of hydrostatic pressure should be restored prior to opening the BOP.

10.2.2 Trapped Gas Below BOPs

Subsequent to control operations during which gas is circulated out the choke line, free gas will remain trapped below the closed preventer; the gas volume can be quite significant with an annular preventer. To prevent rapid unloading of the riser due to trapped gas when the closed preventer is opened or the introduction of a secondary kick due to light density drilling fluid in the riser, close the uppermost rams below the choke line and close the diverter. Open the preventer above the trapped gas and allow this gas to rise toward the surface. Displace the riser with kill fluid and reopen the rams. It may be necessary in extreme cases to close the bottom rams to isolate the hole and fill the riser by circulating through the kill line. This problem becomes more severe with increased water depth and/or BOP size. The basic steps are as follows:

1. Isolate the wellbore by closing a lower set of preventers;
2. Lower the gas pressure by exposing it to a lower hydrostatic pressure;
3. Circulate the BOPs choke and kill lines and riser with kill mud; and,
4. Open the well.

10.2.3 Vessel Motion

Although it may not be a direct cause of a kick, vessel motion complicates kick recognition and can cause wear in the annular BOP or diverter sealing elements.

10.2.3.1 Vessel heave alternately lengthens and shortens the drilling riser and can make the well appear to flow. In extreme cases, it can cause an apparent loss of returns by exceeding the surge capacity of the shale shaker. In severe weather, vessel pitch and roll can conceal changes in pit level.

10.2.3.2 Wear on BOP or Diverter Sealing Elements—Pipe movement through a closed annular BOP or diverter can cause rapid wear of the sealing elements. Pipe movement results from vessel heave or pipe stripping operations or a combination of both. Wear on sealing elements can be minimized by:

1. Adjusting the system closing pressure to the lowest pressure that results in an acceptable closing time,
2. Hanging off the drill pipe as soon as practical after a kick has been identified,
3. Reducing the closing pressure to the lowest practical value during sustained periods of pipe motion, and
4. Adjusting the motion compensator.

Many floating drilling rigs with subsea BOP stacks have ram locks that lock automatically upon closure. Hence, reducing closing pressure will do little to relieve the stress on the rubber packers after the BOP is closed and locked. Consideration should be given to installing rams that do not automatically lock upon closure. Specific recommendations as to closing pressures should be obtained from equipment manufacturers.

10.3 SUBSEA EXCEPTIONS TO CONTROL PROCEDURES

The control techniques discussed under Section 9, "Well Control Procedures—Surface BOPs," apply to subsea operations with the following special considerations:

1. Choke line pressure loss.
2. Establishing circulation.
3. Low fracture gradients in deepwater.
4. Close-in and hang-off operations.

10.3.1 Choke Line Pressure Loss

The choke manifold on a surface BOP installation is located close enough to the BOP stack that the pressure loss in the choke line can be neglected for most installations. The pressure at the choke manifold can be considered the wellhead pressure. In the case of a subsea stack, this is not the case. The pressure loss in the choke line can impose a significant backpressure on the well bore (refer to 4.13.1). This pressure loss can be reduced by taking returns through both choke and kill lines or reducing the circulating rate. Whichever method is used, it is imperative that correct drill pipe pressure is maintained to hold the correct bottom-hole pressure. If the circulating rate is reduced, it is necessary to have pre-determined the circulating system pressure loss for the reduced rate. In the case of wells in deepwater, at least two, and preferably three, reduced circulating rates and pressures and the corresponding choke line pressure losses should be determined. The pressure loss in the choke and kill lines can be determined by circulating down the line (refer to 4.13.1 and 4.13.2 for more detail).

10.3.2 Establishing Circulation

To establish circulation with a subsea BOP stack while maintaining a constant bottom-hole pressure, it is necessary to reduce the surface choke line pressure by an amount equal to the choke line friction loss while bringing the circulating pump up to speed. If the kill line can be used to monitor casing pressure, the choke in the choke line should be used to keep the closed-in kill line pressure constant while bringing the pump up to speed. If the kill line pressure cannot be monitored, the choke line pressure should be reduced by the previously measured choke line pressure loss while bringing the pump up to speed.

10.3.3 Fracture Gradients

Experience in deepwater has shown that low formation breakdown pressures can be expected. The basic cause is that a substantial part of the overburden is water. To avoid formation breakdown, it may be necessary to circulate out a kick at a very slow rate.

10.4 SPECIAL SUBSEA PROCEDURES

10.4.1 Marine Riser Emergency Release

If time and weather conditions permit, the following is an example outline of a procedure to release the drill string before the well is killed. Specifics of each rig and operation will vary and should be planned well before operations begin.

1. Displace the drill string with a kill weight fluid and install a backpressure valve in the drill string.
2. Bleed-off the drill pipe pressure.
3. Pick up the weight of the drill string from the closed pipe ram supporting it.
4. Close the annular preventer and adjust the closing pressure so the tool joints may be stripped into and out of the annular preventer. Open the pipe rams.
5. Strip out enough drill pipe to reach the joint that was hung in the ram preventer (refer to 10.4.3).
6. Install the rig's subsea preventer hang-off tool or loosen the tool joint of the landing joint if a hang-off tool is not available.
7. Strip the drill string back into the hole to place the hang-off tool or loosened tool joint immediately above the closed annular preventer.
8. Close the hang-off ram, bleed the pressure between the preventers, and open the annular preventer.
9. Lower the drill string, landing the hang-off tool or loosened tool joint on the hang-off ram.
10. Release the hang-off tool or back-out the loosened tool joint above the hang-off ram.
11. Close and lock the blind shear rams above the hang-off tool or broken-out tool joint.
12. Close the choke lines; close and lock the applicable pipe rams.
13. Pull the remaining drill string, recover the drilling fluid in the riser, and release the riser.

10.4.1.1 If weather conditions or other well problems prevent the above procedure, an emergency release may be performed per the following general outline:

1. Hang-off as described in 10.4.3.
2. Displace the drill string with a kill weight fluid and pump downinstall a backpressure valve to the receiving sub in the drill string.
3. Bleed off the drill pipe pressure.
4. Shear off the drill pipe using the blind shear rams and leave the shear rams closed.
5. Release the marine riser.

10.4.2 Kick With Drill Pipe Out of Hole

Should a well begin to flow when the drill pipe is out of the hole, following is an outline of a procedure that can be used to regain control:

1. At the first indication of the well flowing, close the blind rams, open the gate valve on the subsea BOP stack to open the choke line, close the choke line at the surface, and record the shut-in pressure. A 0-500 psi gauge is recommended to detect small pressure changes (refer to 4.8.1). If the choke line is filled with water this must be taken into consideration when using the shut-in casing pressure in calculations. Record the kick volume.
2. Run the drill string in the hole to the top of the BOPs. Insert a backpressure valve.

3. Add the hydrostatic pressure of the fluid in the choke line to the surface pressure to determine the pressure below the blind rams.
4. Determine if the pressure below the blind rams can be overbalanced by hydrostatic pressure of the drilling fluid that can be safely contained by the riser. If so, adjust the riser tensioners to support the additional drilling fluid weight and displace the drilling fluid in the riser with drilling fluid of the required density.
5. Close the diverter. Open the BOPs and watch for flow. If the well does not flow, open the diverter and go in the hole.
6. If the well starts to flow, close the blind ram preventer, displace the choke and kill lines with heavy drilling fluid, and circulate until the riser contains drilling fluid of the desired density.
7. Continue going in the hole. Stop periodically, close the pipe rams, and circulate the riser by pumping down the kill line to maintain the required drilling fluid density in the riser.

10.4.3 Close-in and Hang-off Operations

To minimize wear on the annular BOP sealing element, to be prepared for an emergency disconnect, or to minimize trapped stack gas, the drill string can be hung-off in the BOP stack after a kick is shut-in.

1. Stop drilling (if applicable) and position the pipe for the BOPs while sounding the alarm.

Note: Be aware of where tool joints are positioned in BOPs.

2. Shutdown the drilling fluid pumps.
3. Check the well for flow-If it is flowing, perform the shut-in in accordance with step 4 below.
4. If the "soft shut-in procedure" has been selected: open the choke line, close BOP, and close the choke (refer to 4.9.1). If the "hard shut-in procedure" has been selected: close the BOP and open the choke line with the choke closed (refer to 4.9.2).
5. Observe the casing pressure. If the casing pressure will exceed the allowable level, follow the pre-selected contingency plan (refer to 7.4.5).
6. Adjust the closing pressure on the annular preventer to permit stripping of tool joints. (Refer to 12.8 for stripping operations).
7. Check for trapped pressure (refer to 9.6.1 and 10.2.2).
8. Hang-off the drill pipe as follows:
   A. With a motion compensator:
      i. Position a tool joint above the hang-off rams leaving the lower kelly cock (refer to 9.5.5) high enough above the floor to be accessible during the maximum expected heave and tide when the selected tool joint rests on the hang-off rams.
      ii. Close the hang-off rams.
      iii. Carefully lower the drill string until the tool joint rests on the hang-off rams.
      iv. Reduce support pressure on the motion compensator so it will support about half the weight of the drill string above the BOPs plus some overpull to provide drill string tension to aid shearing. Continue with step 9 below.
   B. Without a motion compensator.
      i. Set the slips on the top joint of drill pipe.
      ii. Close the lower kelly cock (refer to 9.5.5).
      iii. Break the kelly/top drive connection above the lower kelly cock and stand it back in the rat hole.
      iv. Pick up the assembled space-out joint, safety valve, and circulating head with the safety valve closed. Make up the space-out joint on the closed lower kelly cock.
      v. Open the lower kelly cock, remove the slips, and position a tool joint above the hang-off rams leaving the safety valve high enough above the floor to be accessible during the maximum expected heave and tide when the selected joint rests on the hang-off rams.
      vi. Close the hang-off rams.
      vii. Carefully lower the drill string until the tool joint has landed on the closed hang-off rams. Slack off the entire weight of the drill string while holding tension on the circulating head with the air tugger or other tension device.
      viii. Connect the circulating head to the standpipe, open the supper safety valve. Continue with step 9 below.
9. Allow the shut-in pressure to stabilize and record pressures.
10. Determine the volume of the kick.
11. Calculate the drilling fluid density required to kill the kick (refer to 9.6.2).
12. Select a kill method.
13. Check rig crew duties and stations.
14. Review and update output and hole volume data and complete the well control worksheet (refer to Appendix B).
15. Inspect the BOP stack with television, if feasible.

11 Well Control Procedures—Recommended Rig Practices

11.1 WELL CONTROL SYSTEM EQUIPMENT INSTALLATION

On drilling rigs, a schematic drawing should be available on the rig showing all system components, equipment sizes, and equipment locations, including the location of the main control panel and remote panel(s). Well completion and well service operations should consider schematic drawings if the operations are expected to be complicated; i.e., high pressure, hydrogen sulfide gas, low pressure thief formations, etc.

11.2 WELL CONTROL EQUIPMENT INSTALLATION TEST

All well control system components shall be inspected and tested to ascertain proper installation and function. Simulate loss of rig air supply to the control system and determine effects, if any, on the primary well and backup systems. Refer to Sections 17 (Surface BOP) and 18 (Subsea BOPS) of API RP 53, *Recommended Practice for Blowout Prevention Equipment Systems for Drilling Wells* and API RP 64, *Recommended Practice for Diverter Systems Equipment and Operations* (reader should check for the latest edition) for general testing considerations.

11.3 CREW DRILLS

Shallow gas flows generally develop quickly; can be difficult to detect early; and, will flow high volumes of gas from abnormally pressured, highly permeable formations. Likewise, inadvertent gas entry in a marine riser or a gas bubble migrating up the annulus can be difficult to detect. All concerned personnel should be familiar with the well control system components and installation and capable of reacting quickly and efficiently to potential situations requiring their use. Drills should be documented, executed, repetitive, and followed-up to correct identified problems. Drills should be clearly announced so all concerned know that a drill, not an actual event, is taking place. Drills generally enhance the crew proficiency in well control situations. When the desired proficiency is attained, periodic drills should be continued to maintain performance. The following drills, frequency, and proficiency levels are considered desirable for drilling operations.

11.3.1 Pit Drill

During a routine operation, the rig supervisor should simulate a gain in pit drilling fluid volume by raising a float sufficiently to cause an alarm to be activated. If automatic equipment is not available, the drills may be signaled by word of mouth. The drilling crew should immediately initiate one of the four procedures discussed in 11.3.2.1 through 11.3.2.4 below, depending on the operation at the time of the drill. A pit drill is terminated when the crew has completed the steps up to, but not including, closing the BOPs. The supervisor initiating the drill should record response time, which should be one minute or less.

11.3.2 BOP Drill

This drill includes all steps of the pit drill in 11.3.1 but is continued through all the steps of closing-in the well. The drill should be repeated on a daily basis until each crew closes-in the well within a span of two minutes. Thereafter, the drill should be repeated weekly to maintain proficiency. Following are simplified drill outlines that should be modified for the specifics of the particular rig, equipment, and operation.

11.3.2.1 On-Bottom Drill

This drill should be carried only to the point of driller recognition, signaled by raising the kelly/top drive and pump shutdown. This is to avoid the danger of stuck pipe.

1. Signal given.
2. Stop drilling or other operation.
3. Position the drill pipe for the BOPs while sounding the alarm.
4. Stop pump.
5. Check for well flow.

11.3.2.2 Tripping Pipe Drill

Drills while tripping drill pipe should be performed after the bit is up in the casing. A full-opening safety valve for each size and type connection in the string must be open and on the floor ready for use. Safety valves must be clearly identified as to size and connection to avoid confusion and lost time when stabbing.

1. Signal given.
2. Position the upper tool joint above the floor and set slips.
3. Stab the full open safety valve on drill pipe.
4. Close the drill pipe safety valve.
5. Close the BOP.

11.3.2.3 Drill Collars or Tool Joints in the BOP Drill

Preparation for this operation must be made in advance. Prior to reaching the drill collars or bottom-hole assembly when pulling out of the hole, the appropriate crossover sub must be placed on a single joint of pipe. A full open safety valve is then made-up on the top of the joint of pipe. Flows that occur with drill collars or the bottom-hole assembly in the BOPs are generally quite rapid since they are usually the result of expansion of a gas bubble close to the surface. A joint of pipe picked up with the elevators is usually easier to stab and make-up than a safety valve alone. Under actual kick conditions (other than drill) if only one stand of drill collars or the bottom-hole assembly remained in the hole it is probably faster to simply pull that last stand and close the blind rams.

1. Signal given.
2. Position the upper drill collar or tool joint and set the slips.
3. Stab the full open safety valve made up on one joint of pipe with the appropriate crossover sub onto the drill collars or tool joint.

4. Lower the collars with joint of pipe into the hole.
5. Close the drill pipe safety valve.
6. Close the pipe rams above the pipe tool joint.

11.3.2.4 Out of the Hole Drill

1. Signal given.
2. Close the blind rams.

11.3.3 Stripping Drill

A stripping drill by at least one crew on each well should be considered. This drill can be conveniently performed after casing is set and before drilling out cement. With drill pipe in the hole, the BOP is closed and the desired pressure trapped. Each member of the crew should be assigned a specific position. Strip sufficient pipe into the hole to establish the workability of the equipment and allow the crew an opportunity to perform their assignments. In addition to establishing equipment reliability, at least one crew on each well is trained. All crews should become proficient in stripping operations. Stripping drills are not recommended for operations involving subsea BOP stacks. For more information on stripping operations, refer to 12.8.

11.3.4 Choke Drill

Choke drills should be performed before drilling out surface casing and each subsequent casing string. With pressure trapped below a closed preventer, use the choke to control casing pressure while pumping down the drill pipe at a prescribed rate. This drill establishes equipment performance and allows the crew to gain proficiency in choke operation. Discharge into a trip tank to accurately monitor flow rates for correlation with choke opening, pump rates, and pressure drops in the circulating system and across the choke. This is particularly important for subsea BOP stacks in deepwater, which may have significant circulating pressure losses in the choke lines.

11.3.5 Hang-off Drill (Subsea BOPs Only)

Following prescribed procedures, the crew should place the drill string in position for hang-off. One hang-off should be made before drilling out of surface pipe to ensure that all necessary equipment is on hand and in working condition. Actual hang-off is not normally performed on subsequent drills. This drill can be conveniently performed in conjunction with the pit drill.

11.4 TRIP TANKS

A trip tank is a low-volume, calibrated tank, which can be isolated from the remainder of the surface drilling fluid system and used to accurately monitor the volume of fluid going into or coming from the well. The primary use is to measure the amount of drilling fluid required to fill the hole while pulling pipe to determine if drilling fluid volume matches pipe displacement. Other uses include measuring drilling fluid or water volume into the annulus when returns are lost, monitoring the hole while logging or following cement job, and calibrating drilling fluid pumps. A trip tank may be any shape if it is calibrated accurately and a means is provided for reading the volume contained in the tank at any liquid level. The readout may be direct or remote, preferably both. The size of the tank and readout arrangement should be such that volume changes in the order of one-half barrel can be easily detected. Tanks containing two compartments with monitoring arrangements in each compartment are preferred as this facilitates removing or adding drilling fluid without interrupting rig operations. Measurement of drilling fluid volume and flow rate is critical in all operations but most critical in floating operations. In floating operations, pit level monitoring devices (floats) should be located in the center of the pits or multi-floats with sequential integration utilized. A trip tank and pit watcher should be considered if vessel movement creates any problem in measuring drilling fluid requirements on trips.

11.5 GAS-CUT DRILLING FLUID

Gas-cut drilling fluid may occur during well control operations. Gas cutting of the drilling fluid column causes relatively small reduction in hydrostatic pressure. The reduction in hydrostatic pressure can be estimated using the chart shown in Figure 11.1. This reduction in hydrostatic pressure is normally not a severe problem except where the casing seat is shallow. However, gas-cut drilling fluid reduces the efficiency of drilling fluid pumps. Foam on the drilling fluid pits may create some misinterpretation and gas cutting can cause an indication of pit volume increase even when there is no flow into the well bore. For proper well control, drilling systems should be equipped with mud-gas separators and degassers to minimize recirculation of gas-cut drilling fluid. Use of a pressurized drilling fluid balance and defoaming agents are also recommended. Refer to 15.9 and 15.10 of API RP 53, *Recommended Practice for Blowout Prevention Equipment Systems for Drilling Wells* for more information on mud/gas separators and degassers.

11.6 TRIP BOOK

A tally should be maintained showing the volume of drilling fluid required to fill the hole after a specified number of stands along with the cumulative volume. Keep this data in a "Trip Book" or on a computer to compare with previous trips. In addition to comparison with theoretical displacement volume this data can be used to spot anomalous well behavior. A similar record should be made of drilling fluid returns while running pipe in the hole. Table 11.1 illustrates an example trip

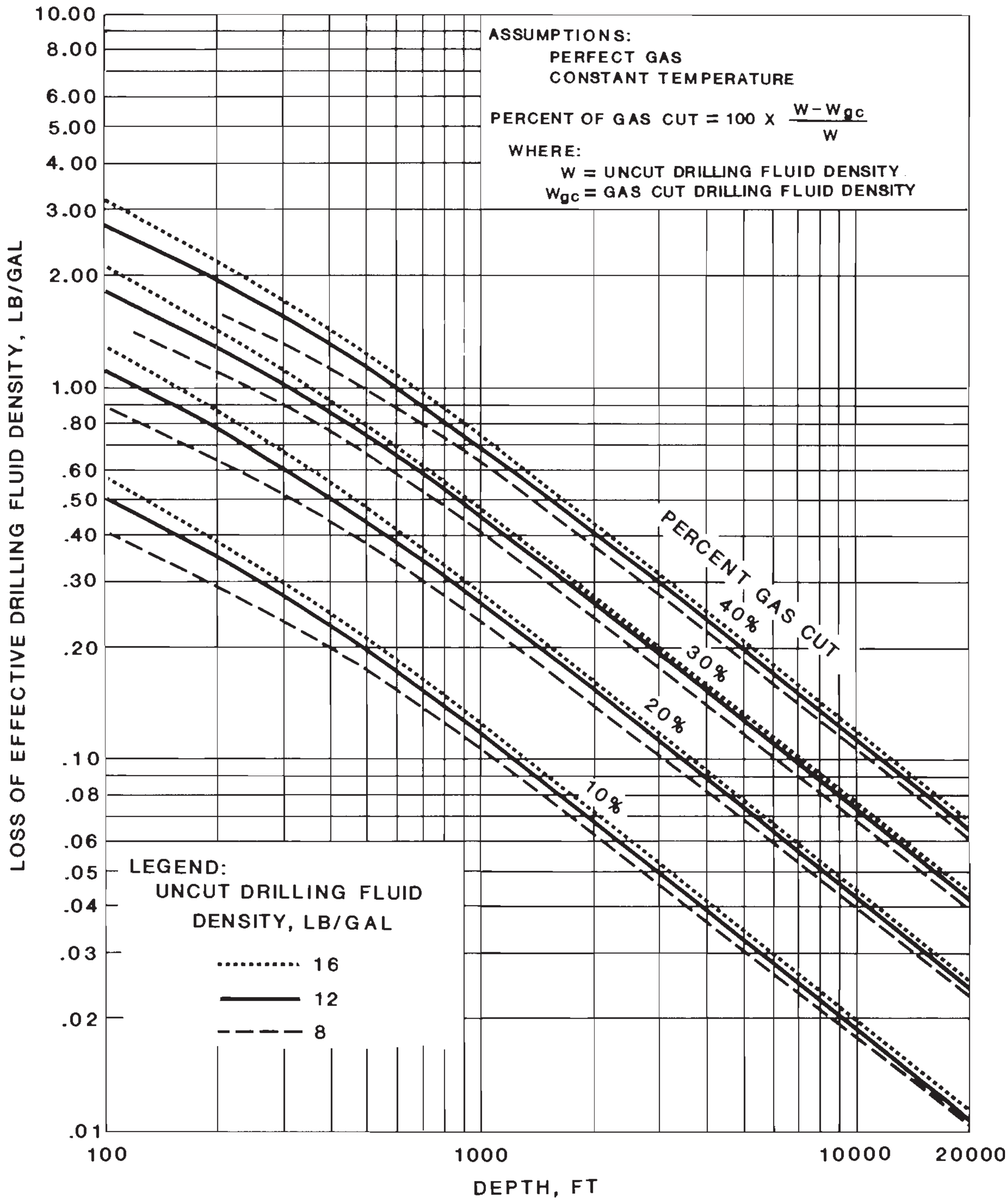

Figure 11.1—Loss of Effective Drilling Fluid Density Due to Gas Cut

book form that could also be used in a spreadsheet format in a computer. Trip books are normally printed and bound in a pocketbook-size driller's log for convenience.

11.7 PRE-KICK INFORMATION

Prevention, control, and circulation of kicks is enhanced by collection of selected information and performing certain calculations prior to a kick. The following outlines some desirable information.

11.7.1 Formation Integrity

Following the cementing of each casing string and drilling out the shoe, a formation competency test or a leak-off test may be conducted to assure that the formation will support the maximum required hydrostatic pressure. Either test may be repeated as the well is being drilled to maintain reliable information. Note: Formation competency tests and leak-off tests are not synonymous (refer to 4.7, 4.7.1, and 4.7.2).

11.7.2 System Pressure Losses

Daily, while drilling or after a significant change in the circulating system pressure, the pressure drop (circulating pressure) throughout the circulation system should be obtained and recorded on the recommended well control worksheet (refer to Appendix B) and the tour report. The pump rate used to obtain this pressure drop should be the reduced rate that would be used to circulate a kick from the well.

11.7.3 Capacities—Displacement

Drilling fluid tank capacities should be calculated in barrels per inch for both the entire surface drilling fluid system and individual tanks. The capacities of tubing or drill pipe, tool joints, drill collars, marine riser, casings, well bore, and choke and kill lines should be tabulated. The annular volume between any possible combination of pipe/pipe, pipe/hole, and service tool/hole/pipe should be calculated. Displacement of the pipe string (tubing, casing, drill pipe, drill collars, regular stabilizers, service tools, etc.) should be calculated and tabulated at intervals and maintained at the rig for ready reference in the event of a kick.

11.7.4 Pressure Limitations of Installed Equipment, Tubulars, Etc.

The maximum allowable pressure that may be applied against each component within the well control system should be determined and used in evaluating component pressure protection and the advisability of circulating a gas kick to the surface.

11.7.5 Drilling Fluid Pump(s)

The volume per stroke output for each pump should be obtained and entered on the tour report at periodic intervals while drilling the well.

11.7.6 Drilling Fluid Mixing Capability

The rig's actual maximum efficient rate of mixing drilling fluid should be determined. This mixing rate and its effect on drilling fluid properties should be used in planning well control operations.

11.7.7 Post-kick Information

Following control of a kick, a safe trip margin and drilling fluid density should be determined. The drilling fluid density should be sufficient to permit safe withdrawal of the drill pipe from the hole based on swab and fracture considerations.

11.8 MINIMIZE TIME OUT OF THE HOLE

Time with pipe out of the hole should be minimized. Particular care should be taken to have all necessary crossover connection(s) readily available when running service tools that may interfere with closure of the rams in the BOP. An example is long core barrel: It is probably too long to clear the ram closure zone and its outside diameter too large to fit the pipe rams. Having the proper connections readily available ensures that pipe movement can be accomplished in order to close more than the annular BOP. In case of equipment repair on drilling rigs, the pipe should be run at least back to the last casing shoe, if possible, before repairs are undertaken. In well servicing operations, when making equipment repairs, effecting routine maintenance, or shutting down overnight, the pipe should be run to a sufficient depth to ensure that the well can be controlled.

11.9 TRIP MARGIN

The use of a trip margin is encouraged to offset the effects of swabbing. The additional hydrostatic pressure permits some degree of swabbing without losing primary well control.

11.10 SHORT TRIP

After tripping and circulating "bottoms-up," the amount of gas, saltwater, or oil contamination will enable the evaluation of operating practices affecting swabbing. Adjustments in pulling speed, drilling fluid flow properties, and/or drilling fluid density may be warranted. A short trip and circulating