WELL CONTROL PRINCIPLES AND PROCEDURES FOR COMPLETION, RECOMPLETION, AND WORKOVER (C,R,&W)

A. INTRODUCTION

Oil and gas well control procedures for C, R, & W operations are significantly different than those used when drilling. Though basic pressure considerations are the same, implementation methods vary greatly due to well conditions, which are often unique to individual wells. These conditions include the type of completion, formation pressures exposed to the wellbore, and the reasons for performing the workover.

Routine C,R, & W operations often require the implementation of various well control procedures. The most common are 1) killing a producing well and 2) controlling kicks, which occur during a workover. An understanding of the differences between these two operations and the effect of routine operations on well control is essential for the workover supervisor.

In this section, specific attention will be paid to pressure and its effect on well control, causes of kicks and considerations, which affect selection of proper kill procedures.

B. FUNDAMENTALS OF PRESSURE

An understanding of basic pressure principles is essential to understanding well control. Pressure (P) is defined as Force (F) per unit area (A). This concept is illustrated in Figure 1 which shows a brick lying on a table.

**PRESSURE/FORCE/AREA RELATIONSHIP**

Sub-figure (a) shows arrows labeled \( W_b \) and \( F_T \) which represent the forces exerted by the brick and table respectively. These forces, though shown as applied at a single point (arrows tip to tip), are actually distributed over the area of contact between the brick and table. Sub-figure (b) shows the brick lying on its large side (4 inches wide x 8 inches long), thus the total force is evenly distributed over that area. Knowing the weight of the brick, say 5 pounds, we can calculate the forces acting on any given part of the brick or table.
Example 1

**Imperial (API)**

\[ F = \text{Weight of brick} = 5 \text{ pounds} \]
\[ A = \text{Area of contact} = 8'' \times 4'' = 32 \text{ square inches} \]
\[ P = \text{Pressure} = \text{Force per area} = \frac{F}{A} = \text{pounds per square inch (psi)} \]
\[ P = \frac{5}{32} = .156 \text{ lbs/sq. in. or .156 psi} \]

If a second brick is stacked on top of the first as in Sub-figure (c), the weight (Force) of the bricks double but the area of contact remains the same, thus the pressure doubles. Again looking at the equations for pressure:
\[ P = \frac{F}{A} = \frac{2W_b}{A} = (2 \times 5) / 32 = 10 / 32 \]
\[ P = .312 \text{ psi} \]

If the original brick were to be set on end as shown in Sub-figure (d), the force \( W_b \) remains the same (5 lbs) but now the area of contact is smaller (2'' x 4''). Thus the pressure is:
\[ P = \frac{F}{A} = \frac{W_b}{A} = 5 / (2 \times 4) = 5 / 8 \]
\[ P = .625 \text{ psi} \]

**Metric (SI)**

**Note:** on practice “Kilogram”, which is value of mass, is used as value of weight.

Actual value of weight is “Newton”: \( 1 \text{ N} = 1 \text{ kg} \times 0.981 = 0.981 \text{ kg} \)

Metric oilfield calculations use “Kilopascal” (kPa) as value of pressure.

\( 1 \text{ kPa} = 1000 \times (\text{Newton (N)} / \text{m}^2) = 981 \text{ kg/m}^2 \)

\[ F = \text{Weight of brick} = 2.27 \text{ kilogram} \]
\[ A = \text{Area of contact} = 0.2 \text{ m} \times 0.1 \text{ m} = 0.02 \text{ m}^2 \]
\[ P = \text{Pressure} = \text{Force per area} = \frac{F}{A} = \text{kilogram per square meter} \]
\[ P = \frac{2.27}{0.02} = 113.5 \text{ kg/m}^2 = 0.1157 \text{ kPa} = 1.16 \times 10^{-1} \text{ kPa} \]

If a second brick is stacked on top of the first as in Sub-figure (c), the weight (Force) of the bricks double but the area of contact remains the same, thus the pressure doubles. Again looking at the equations for pressure:
\[ P = \frac{F}{A} = \frac{2W_b}{A} = (2 \times 2.27) / 0.02 = 4.54 / 0.02 = 227 \text{ kg/m}^2 = \]
\[ = 0.2314 \text{ kPa} = 2.31 \times 10^{-1} \text{ kPa} \]
\[ P = 2.31 \times 10^{-1} \text{ kPa} \]

If the original brick were to be set on end as shown in Sub-figure (d), the force \( W_b \) remains the same (2.27 kg) but now the area of contact is smaller (0.05 m x 0.1 m). Thus the pressure is:
\[ P = \frac{F}{A} = \frac{W_b}{A} = 2.27 / (0.05 \times 0.1) = 2.27 / 0.005 = 454 \text{ kg/m}^2 = 0.462 \text{ kPa} \]
\[ P = 0.462 \text{ kPa} = 4.62 \times 10^{-1} \text{ kPa} \]

These examples illustrate concepts of force and pressure caused by gravity acting on a solid body; however, they can be directly applied to fluids. The only difference is that fluids assume the shape of the container they are in and resulting pressures are a function of the total fluid weight and the area of contact between the container and the body supporting the fluid filled container.

### C. TYPES OF WELL PRESSURE

Fluid pressures are of primary concern in drilling and C, R, & W operations because they are:
1. The source of reservoir drive, which causes reservoir fluids to flow.
2. The primary means of controlling the flow of reservoir fluids.

Static and dynamic pressures are the two basic categories of fluid pressure of concern when discussing well activities.

**Static pressure** is the pressure observed when a well is completely shut-in, a no-flow condition. At this time, only two types of pressure are acting; formation and hydrostatic.

**Formation pressure** is the pressure contained inside the rock pore. Knowledge of formation pressure is
important, because it will dictate the mud weight required in the well. If the formation pressure is greater than the pressure exerted by the mud column, fluids (gas, oil, or saltwater) can flow into the well from permeable formations.

1. **Origin of Formation Pressure:**
   Formation pressure is due to the action of gravity on the liquids and solids contained in the earth's crust. If the pressure is due to a full column of saltwater with average salinity for the area, the pressure is defined as normal. If the pressure is partly due to the weight of the overburden and is therefore greater, the pressure is known as abnormal. Pressures below normal due to depleted zones or less than full fluid columns to the surface are called subnormal pressure.

2. **Normal Pressure**
   In the simplest case, usually at relatively shallow depth, the formation pressure is due to the hydrostatic pressure of formation fluids above the depth of interest. For example saltwater is the common formation fluid along the U.S. Gulf Coast and averages about 8.95 ppg (1070 kg/m³) or 0.465 psi / ft (10,5 kPa/m). Therefore 0.465 psi / ft is considered the normal formation pressure gradient for the Gulf Coast. Formation pressure gradients above 0.465 psi / ft are considered abnormal. The normal formation pressure gradient for other areas can be different, depending on average formation water salinity. Pressure in a normal pressured formation is simply the gradient times the true vertical depth. Normally pressured formations are usually drilled with about 9.5 to 10.0 ppg (1140 to 1200 kg/m³) mud in the hole.

3. **Abnormal Pressure**
   For the formation pressure to be normal, fluids within the pore spaces must be interconnected to the surface. Sometimes a seal or barrier interrupts the connection. In this case, the fluids below the barrier must also support part of the rocks or overburden. since rock is heavier than fluids, the formation pressure can exceed the normal hydrostatic pressure. The formation is abnormally pressured, overpressured, or geopressed.

   **Hydrostatic pressure** is the pressure resulting from the weight of a static column of fluid, whether liquid or gas. Example 2 and Figure 2 are used here to illustrate the concept of hydrostatic pressure.

   This figure shows two columns of fluid contained by two cylindrical containers of different dimensions. Both containers hold the same volume of fluid and both fluids are of the same density. Thus the weight of each container is the same.
Example 2
Imperial (API)

For purposes of this example use the following:

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Unit</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Cylinder Diameter (a)</td>
<td>inches</td>
<td>2</td>
</tr>
<tr>
<td>Fluid column Depth (a)</td>
<td>inches</td>
<td>12</td>
</tr>
<tr>
<td>Fluid density</td>
<td>pounds per cubic inch</td>
<td>1</td>
</tr>
<tr>
<td>Area (a)</td>
<td>in²</td>
<td>3.1416</td>
</tr>
<tr>
<td>Volume (a)</td>
<td>in³</td>
<td>37.7</td>
</tr>
<tr>
<td>Fluid Weight</td>
<td>lbs</td>
<td>37.7</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Unit</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Cylinder Diameter (b)</td>
<td>inches</td>
<td>6</td>
</tr>
<tr>
<td>Fluid column Depth (b)</td>
<td>inches</td>
<td>1.33</td>
</tr>
<tr>
<td>Fluid density</td>
<td>pounds per cubic inch</td>
<td>1</td>
</tr>
<tr>
<td>Area (b)</td>
<td>in²</td>
<td>28.35</td>
</tr>
<tr>
<td>Volume (b)</td>
<td>in³</td>
<td>37.7</td>
</tr>
<tr>
<td>Fluid Weight</td>
<td>lbs</td>
<td>37.7</td>
</tr>
</tbody>
</table>

If we now apply the definition of pressure as discussed in the brick example we see that:

Pressure container (a) = \( \frac{W(a)}{A(a)} \)

\[ \text{Pressure (a)} = \frac{37.7}{3.1416} = 12.0 \text{ psi} \]
Pressure container (b) = \( P(b) = \frac{W(b)}{A(a)} \)

= \( \frac{37.7}{28.35} \)

= 1.33 psi

**Metric (SI)**

For purposes of this example use the following:

- Cylinder Diameter (a) = 5 centimeters = 0.05 m
- Fluid column Depth (a) = D(a) = 30.48 cm = 0.3 m
- Fluid density = \( d(a) = 27,680 \text{ kg/m}^3 \) (kilograms per cubic meter)
- Area (a) = \( A(a) = 2 \times 10^{-3} \text{ m}^2 \)
- Volume (a) = \( V(a) = A(a) \times D(a) = 2 \times 10^{-3} \text{ m}^2 \times 0.3 \text{ m} = 6 \times 10^{-4} \text{ m}^3 \)
- Fluid Weight = \( W(a) = V(a) \times d(a) = 6 \times 10^{-4} \text{ m}^3 \times 27,680 \text{ kg/m}^3 = 16.6 \text{ kg} \)

- Cylinder Diameter (b) = 15.24 cm = 0.15 m
- Fluid column Depth (b) = D(b) = 3.4 cm = 0.034 m
- Fluid density = \( d(b) = 27,680 \text{ kg/m}^3 \)
- Area (b) = \( A(b) = 1.83 \times 10^{-2} \text{ m}^2 \)
- Volume (b) = \( V(b) = A(b) \times D(b) = 1.83 \times 10^{-2} \text{ m}^2 \times 3.4 \times 10^{-2} \text{ m} = 6 \times 10^{-4} \text{ m}^3 \)
- Fluid Weight = \( W(a) = V(a) \times d(a) = 6 \times 10^{-4} \text{ m}^3 \times 27,680 \text{ kg/m}^3 = 16.6 \text{ kg} \)

If we now apply the definition of pressure as discussed in the brick example we see that:

- Pressure container (a) = \( P(a) = \frac{W(a)}{A(a)} \)
  = \( \frac{16.6 \text{ kg}}{(2 \times 10^{-3}) \text{ m}^2} \)
  = \( 8.3 \times 10^3 \text{ kg/m}^2 = 8.5 \text{ kPa} \)

- Pressure container (b) = \( P(b) = \frac{W(b)}{A(a)} \)
  = \( \frac{16.6 \text{ kg}}{(1.83 \times 10^{-2}) \text{ m}^2} \)
  = \( 9 \times 10^4 \text{ kg/m}^2 = 9.2 \times 10^{-1} \text{ kPa} \)

These are the pressures, which static fluid columns of the configurations shown exert on the bottom of their respective containers, referred to as Hydrostatic Pressure. This pressure is the primary means of controlling Formation Pressure.

Referring again to our example in Figure 2 we can see that the pressure exerted by any fluid column is the result of only two parameters; fluid density, and the true vertical depth of the fluid column.

For example 2(a) we had a 12-inch (0.3 m) column of 1 lb/in\(^3\) (27,680 kg/m\(^3\)) fluid and the resulting pressure was 12 psi (8.5 kPa). We can relate these values to density and depth by dividing the hydrostatic pressure by the column depth to obtain a pressure gradient or pressure per increment of column depth or height.

\[
\text{API: Pressure gradient (a) = } \frac{12 \text{ psi}}{12 \text{ inches}} = 1 \text{ psi per inch} \\
\text{SI: } = \frac{8.5 \text{ kPa}}{0.3 \text{ m}} = 28.3 \text{ kPa/m}
\]

If the statement that hydrostatic pressure is related to only density and column depth, the pressure gradient just calculated applied to the depth of fluid in (b) should give the same value of hydrostatic pressure as previously calculated, 1.33 psi (0.92 kPa).
In these examples we used units of pounds per cubic inch for density and inches for depth. However, these units are not easily used for well applications where volumes are measured in barrels and column depth is measured in feet. Therefore, we will use the following units for all well control calculations:

**API**
- Density in pounds per gallon (ppg)
- Depth in feet (ft)
- Pressure gradient in pounds per square inch per foot (psi/ft)
- Pressure in pounds per square inch (psi)

**SI**
- Density in kilograms per cubic meter (kg/m³)
- Depth in meters (m)
- Pressure gradient in kilopascals per meter (kPa/m)
- Pressure in kilopascals (kPa)

The previous discussion was presented to introduce the concepts of pressure and to develop two very important equations used in well control calculations. The two equations developed are those for Pressure Gradient and Hydrostatic Pressure, including the necessary unit conversion factor (API = 0.052 psi/ft/ppg; SI = 0.00981), these equations are:

**API**
- Eq. 1 - Pressure Gradient (psi/ft) = Fluid Density (ppg) x 0.052 psi/ft/ppg.
- Eq. 2 - Hydrostatic Pressure (psi) = Pressure Gradient (psi/ft) x Depth (ft).

From these two we can develop:
- Eq. 3 - Hydrostatic Pressure (psi) = 0.052 x Density (ppg) x Depth (ft).

**SI**
- Eq. 1 – Pressure Gradient (kPa/m) = Fluid Density (kg/m³) x 0.00981
- Eq. 2 – Hydrostatic Pressure (kPa) = Pressure Gradient (kPa/m) x Depth (m)
- Eq. 3 – Hydrostatic Pressure (kPa) = 0.00981 x Density (kg/m³) x Depth (m)

These equations should be remembered because they are the basis of all well control calculations and find use in other routine operations as well. In addition to these equations you should also remember:

1. Use true vertical depth (TVD) for all hydrostatic pressure and pressure gradient calculations.
2. Hydrostatic pressure depends only on fluid density and depth.

**Example 3**

**API**

Given: Mud Density = 11.5 ppg
- Well Depth = 9500 feet (TVD)
- Well Depth = 9700 feet (MD)

Find: 1. Pressure Gradient and;
2. Hydrostatic Pressure

Solution:
1. Pressure Gradient - from Eq.1:
11.5 ppg x .052 psi/ft/ppg = .598 psi/ft

2. Hydrostatic Pressure - from 1; Eq.2 & 2; Eq.3:
   a. .598 psi/ft x 9500 ft = 5681 psi
   b. .052 psi/ft/ppg x 11.5 ppg x 9500 ft = 5681

As you can see the given well depth of 9700 ft (MD - which is measured depth) was not part of the solution - **Always use True Vertical Depth (TVD) in pressure calculations**.

Given: Mud Density = 1379 kg/m³
Well Depth = 2895.6 m (TVD)
Well Depth = 2956.6 m (MD)
Find: 1. Pressure Gradient and;
     2. Hydrostatic Pressure

Solution:
1. Pressure Gradient - from Eq.1:
   1379 kg/m³ x 0.00981 = 13.5 kPa/m

2. Hydrostatic Pressure - from 1; Eq.2 & 2; Eq.3:
   a. 13.5 kPa/m x 2895.6 m = 39100 kPa
   b. 0.00981 x 1379 kg/m³ x 2895.6 m = 39100 kPa

As you can see the given well depth of 2956.6 m (MD - which is measured depth) was not part of the solution - **Always use True Vertical Depth (TVD) in pressure calculations**.

Equivalent Density - the density of fluid required to produce a given hydrostatic pressure at a specified depth within a well - is another pressure-related concept of importance to the well control supervisor.

Rearranging equation 3 gives an equation for equivalent density:

\[
\text{API} \quad \text{Eq. 4 - Equivalent Density} = \frac{P}{.052 D} \text{ where:}
\]
\[
P = \text{required pressure}
\]
\[
D = \text{specified depth}
\]

\[
\text{SI} \quad \text{Eq. 4 – Equivalent Density} = \frac{P}{0.00981 \times D} \text{ where:}
\]
\[
P = \text{required pressure}
\]
\[
D = \text{specified depth}
\]

This equation is used to calculate the mud weight required to kill a well prior to beginning a workover or after taking a kick. Other uses include calculation of equivalent mud weights, which would result in fracturing formations and equivalent weights resulting from holding a back pressure on a choke during kill operations.

Dynamic pressures are pressures acting on a well as the result of circulating the well service fluid (WSF). Two concepts of importance are the circulating pressure and equivalent
circulating density.

**Circulating pressure** is the total pressure required to pump the well service fluid (mud) from the pump, through surface lines, the work string, the annulus, through a choke, and back to the surface pits. WSF enters the circulating system under pressure from the rig pump. The WSF pressure is maximum at the pump and continuously drops as it passes through the circulating system due to friction losses between the fluid and system components. When the fluid returns to the pits the pressure is essentially zero, having lost all of the pressure originally imparted to it by the pump.

The size of the pressure loss occurring in each component of the circulating system is a function of WSF properties, flow rate and flow areas, with the largest losses occurring in the work string and through tools placed in the work string. Each of these pressure losses is important because of the overall affect they may have on bottom hole pressure and well control procedures. Excessive pressure losses can severely limit options available to the workover supervisor should a kick occur.

Surface pressure losses and losses through the work string are important because they are useful in determining the actual pressure being exerted at the bottom of the well.

The sum of these two pressures, combined with the annular and choke pressure losses, will result in a surface pump pressure, which must be closely monitored at all times.

Though pressure losses throughout the circulating system are considered to be important, **those losses, which directly affect the bottomhole pressure, are of prime interest during well control operations**. These losses are **annular pressure losses**, and **choke pressure**.

**Choke pressure** is the pressure loss created by directing the return flow from a closed-in well through a small opening or orifice for the purpose of creating a back pressure on the well while circulating out or killing a kick. Choke or back pressure will be imposed on all points in the circulating system, including the open hole. In addition, a back pressure on the well will be induced by the annular pressure loss and any pressure losses through the choke manifold and/or through long choke flow lines.

**Annular pressure losses** occur in the annulus between the casing/hole and the work string. These losses create the need for increased bottomhole pressure to allow the WSF to be circulated to the surface.

**Equivalent Circulating Density** is the density of static fluid column required to produce a hydrostatic pressure equal to the bottomhole circulation pressure.

**Bottomhole pressure** in the well is equal to the sum of all pressures acting at total depth. When the hole is full and the mud column is at rest, bottomhole pressure is the same as mud hydrostatic. However, while circulating, and during other operations, the bottomhole pressure may be more or less than mud hydrostatic.

**Bottomhole Circulating Pressure** is defined as the combination of mud hydrostatic pressure and annular pressure losses. If circulating through a choke or separator at the surface, these back pressures must also be added to mud hydrostatic to obtain a total bottom hole
pressure. If the well is closed in under pressure, the bottomhole pressure is equal to hydrostatic pressure plus closed-in casing pressure.

Examples of conditions causing bottomhole pressures less than mud hydrostatic are: hole not filled with mud, hole partially filled with gas, or other fluid less dense than the mud, and swabbing.

**Differential pressure** is the difference between wellbore and formation pressures. The differential is positive if the wellbore pressure is the greater of the two and negative if the reverse is true. A positive differential pressure often is called an overbalance. The term “underbalance” is used when the formation pressure exceeds the wellbore pressure.

**Swab pressure** is the temporary reduction in wellbore pressure that results from the upward movement of pipe in the hole. **Surge pressure** is the opposite effect whereby wellbore pressure is temporarily increased. The movement of the work string through the wellbore can be likened to the movement of a loosely fit piston through a vertical cylinder. A pressure reduction or suction pressure occurs below as the piston or the pipe is moved upward in the cylinder or wellbore and a pressure increase occurs below as they move downward.

Swab and surge pressures are mostly affected by the velocity of upward or downward movement in the hole. Other factors affecting these pressures are:

(a) Mud gel strength
(b) Mud weight
(c) Mud viscosity
(d) Annular clearance between pipe and casing
(e) Annular restrictions

In order to prevent the influx of formation fluids into the wellbore during times when the pipe is moved upward form bottom, the difference between mud hydrostatic and swab pressure must not fall below formation pressure, The **trip margin** is a density difference which is slightly greater than the equivalent density of the swab pressure at total depth. Trip margin is selected to ensure that the difference between mud hydrostatic and swab pressure will not drop below formation pressure.

**Fracture pressure** is the amount of well pressure an exposed formation can withstand before it fails or "fractures". Should a fracture occur, whole mud is lost to the formation and a well kick is likely to occur. Fracture pressure normally increases with depth and is therefore normally expressed as a gradient or an equivalent density with units of psi/ft (kPa/m) or ppg (kg/m³), respectively.

Formation fracture pressures depend on many variables including (1) depth, (2) rock type, and (3) formation pressure. Several authors have studied these variables and shown that shale sections will generally fracture with pressures less than those required for sand sections. Although most completion practices will attempt to isolate the producing interval from other zones, it should be assumed that a small section of shale is exposed. As a result, the formation fracture pressure must be calculated using shale as the rock type. This conservative approach yields a minimum value for possible fracture pressures.

Calculation procedures for the determination of fracture pressure (otherwise termed
fracture gradient) generally involve complex equations and graphs. However, this fracture pressure is normally known or readily available during C, R & W operations. Example 4 illustrates calculation of fracture pressure using a fracture density of 16 ppg (1919 kg/m³).

Fracture density is simply the equivalent density, which would cause formation fracture at a given depth.

**Example 4**

A workover is to be performed on a well with the characteristics described below.

1. What would be the minimum fracture pressure (FP) under the given conditions? In addition,
2. What static tubing pressure (STP) would fracture the formation?

**Data:**
- Perforations - 9100 ft TVD
- Formation pressure - 5200 psi
- Produced fluid gradient in tubing - .087 psi/ft (gas)
- Equivalent fracture density - 16 ppg

**Solution:**
1. Fracture Pressure (FP):
   \[ FP = 0.052 \text{ psi/ft/ppg} \times 16 \text{ ppg} \times 9100 \text{ ft} = 7571 \text{ psi} \]
2. Static Tubing Pressure to fracture formation:
   a. Full Gas Column:
      \[ STP = 7571 \text{ psi} - (0.087 \text{ psi/ft} \times 9100 \text{ ft}) = 6780 \text{ psi} \]
   b. Full Column of 11.5 ppg Kill Fluid:
      \[ STP = 7571 \text{ psi} - (0.053 \text{ psi/ft/ppg} \times 11.5 \text{ ppg} \times 9100 \text{ ft}) = 2129 \text{ psi} \]

**SI**

A workover is to be performed on a well with the characteristics described below.

1. What would be the minimum fracture pressure (FP) under the given conditions? In addition,
2. What static tubing pressure (STP) would fracture the formation?

**Data:**
- Perforations – 2774 m TVD
- Formation pressure – 35 866 kPa
- Produced fluid gradient in tubing – 1,97 kPa/m (gas)
- Equivalent fracture density – 1919 kg/m³

**Solution:**
1. Fracture Pressure (FP):
   \[ FP = 0.00981 \times 1919 \text{ kg/m³} \times 2774 \text{ m} = 52 222 \text{ kPa} \]
2. Static Tubing Pressure to fracture formation:
   a. Full Gas Column:
      \[ STP = 52 222 \text{ kPa} – (1,97 \text{ kPa/m} \times 2774 \text{ m}) = 46 \text{ 757,22 kPa} \]
   b. Full Column of 1379 kg/m³ Kill Fluid:
      \[ STP = 52 222 \text{ kPa} – (0,00981 \times 1379 \text{ kg/m³} \times 2774 \text{ m}) = 14 \text{ 695 kPa} \]
Pressure/Volume Considerations become very important as a part of well control activity. All fluids under pressure will change in volume as the pressure changes. As pressure increases, the volume of the fluid will decrease, i.e. the fluid will expand. Volume of a fluid is related to a lesser extent to its temperature and decrease with a decrease in temperature. Regardless of the reason for volume change, however, the relative compressibility of liquids and gases is an important factor in well control.

Liquids of concern in well control include mud, saltwater, and oil, and combinations of these liquids. Since the compressibility of these liquids is low, little change in volume due to pressure or temperature changes should be expected as liquids are circulated from the wellbore.

Gases are very compressible and are subject to large changes in volume as they percolate or are circulated from the wellbore. The expansion of a gas bubble while circulating out a kick will cause the choke pressure to rise and the pit level to increase. Volume of a gas bubble will roughly double each time the depth and therefore, the hydrostatic pressure of an open well is halved. If \( V \) is the volume of gas, \( P \) the pressure and disregarding temperature, then the relationship of \( V \) to \( P \) for a gas can be expressed as shown in Figure 3 and Equation 5 or 6 below:

\[
\text{Eq. 5: } PV = \text{Constant} \quad \text{or,} \quad \text{Eq. 6: } P_1V_1 = P_2V_2
\]

**Example 5**

**Given:**
- Depth = 8000 ft
- Gas bubble = 200 ft \((V_1)\)
- Mud weight = 9.5 ppg

**Find:**
- Pressure at 8000 ft \((P_1)\)
- Pressure at 1000 ft \((P_2)\)
- Length of bubble at 1000 ft \((V_2)\)

**Solution:**

\[
V_2 = \frac{P_1V_1}{P_2}
\]

Pressure at 8000 ft; (Eq. 2)
\[
P_1 = .052 \times 9.5 \text{ ppg} \times 8000 \text{ ft} = 3952 \text{ psi}
\]

Pressure at 1000 ft; (Eq. 2)
\[
P_2 = .052 \times 9.5 \text{ ppg} \times 1000 \text{ ft} = 494 \text{ psi}
\]

Length of bubble at 1000 ft (Eq. 6)
\[ V_2 = \frac{(3952 \times 200)}{494} = 1600 \text{ ft} \]

\[ \text{SI} \]

Given: Depth = 2440 m  
Gas bubble = 5.7 m \((V_1)\)  
Mud weight = 1139 kg/m³

Find: Pressure at 2440 m \((P_1)\)  
Pressure at 305 m \((P_2)\)  
Length of bubble at 305 m \((V_2)\)

Solution: \[ P_1 V_1 = P_2 V_2 \]

\[ V_2 = \frac{(P_1 V_1)}{P_2} \]

Pressure at 2440 m; (Eq. 2)

\[ P_1 = 0.00981 \times 1139 \text{ kg/m}^3 \times 2440 \text{ m} = 27264 \text{ kPa} \]

Pressure at 305 m; (Eq. 2)

\[ P_2 = 0.00981 \times 1139 \text{ kg/m}^3 \times 305 \text{ m} = 3408 \text{ kPa} \]

Length of bubble at 305 m (Eq. 6)

\[ V_2 = \frac{(27264 \text{ kPa} \times 5.7 \text{ m})}{3408 \text{ kPa}} = 45.6 \text{ m} \]

Gas Cut Mud is often considered a major source of well control problems. Small amounts of gas sometimes enter the wellbore due to swabbing or other slight underbalance conditions. This gas is subjected to full mud hydrostatic pressure in the wellbore. As the gas percolates or is circulated from the wellbore the hydrostatic pressure decreases and the gas expands. This expansion of small quantities of gas from bottomhole to the surface can cause gas cutting and a large reduction in the density of the drilling fluid as measured at atmospheric pressure. However, this large reduction in surface density is not reflected as a large decrease in bottomhole pressure since the gas in the mud is nearly fully compressed at relatively shallow depth and the average density throughout the well is relatively unaffected.

**D. CAPACITY, VOLUME, DISPLACEMENT CALCULATIONS**

In well control and in routine drilling operations frequent calculations of capacity, volume, and displacement must be made. A brief review of the mechanics involved is included in this section.

Capacity refers to the volume of fluid a container is capable of holding. Capacity is constant as long as the dimensions of the container are constant. Volume refers to the quantity of fluid actually present in the container. Displacement is the volume of a fluid displaced by placing a solid, such as a drill pipe into a specified volume of fluid.

In workover operations, an inventory of WSF capacity and volume is essential. Total capacity can be approximated by adding capacity of the pits, the surface circulation lines and the hole. Capacity of the pits is usually expressed as bbls/in. Total capacity of the pits and surface lines and cased hole can be calculated accurately. The capacity of any open hole must be estimated by assuming a reasonable factor for wash-out beyond bit size. Capacity of the average size open hole, as well as the capacity of the drill pipe, casing, and tubing can easily be
calculated with capacity values expressed in units such as bbls/ft. Tables provided in Appendix B list values of volume capacity and displacement for the most common pipe and hole size.

Calculations of Capacity, Volume and Displacement are relatively simple if the dimensions of the respective containers are known. Using values provided in the respective sections of Appendix B, direct calculations of these parameters can be made knowing only pipe size and weight and length or depth of that size pipe. Pit volume can be found knowing only the length, width, and height of the mud pit and the height of the mud stored in them.

An important point to be recognized is that when drilling, the hole represents an "open system" where hole capacity changes as the well is drilled. This results in constant changes in volume of mud in both the pits and the hole. It is therefore very important to constantly monitor depth and change in pit volume.

In C, R & W operations the hole is normally cased and of a known constant depth. The system therefore represents a closed system and the volume of WSF in the total circulating system is constant. This makes calculations of capacity, volume and displacement much easier and more accurate.

## Pits

The capacity and volume of a rectangular pit or tank can be calculated as shown in Example 6a.

---

### Example 6a

**API**

**Given:** Pit dimensions: 40 ft long, 8 ft wide, 7 ft deep

**Find:**

1. Pit capacity in barrels
   
   \[
   40 \text{ ft} \times 8 \text{ ft} \times 7 \text{ ft} = 2240 \text{ ft}^3 
   \]
   
   \[
   2240 \text{ ft}^3 \times \left( \frac{1 \text{ bbl}}{5.61 \text{ ft}^3} \right) = 400 \text{ bbl} 
   \]

2. Pit capacity in bbls/in
   
   \[
   400 \text{ bbl} \times \left( \frac{1}{7 \text{ ft}} \right) \times \left( \frac{1 \text{ ft}}{12 \text{ in}} \right) = 4.76 \text{ bbl/in} 
   \]

3. Pit volume equivalent to 13 inches of fluid
   
   \[
   \text{Vol.} = 4.76 \text{ bbl/in} \times 13 \text{ in} = 62 \text{ bbl} 
   \]

**SI**

**Given:** Pit dimensions: 12,2 m long, 2,4 m wide, 2,1 m deep

**Find:**

1. Pit capacity in m³
   
   \[
   12,2 \text{ m} \times 2,4 \text{ m} \times 2,1 \text{ m} = 61,5 \text{ m}^3 
   \]

2. Pit capacity in m³/cm
   
   \[
   61,5 \text{ m}^3 / 210 \text{ cm} = 0,29 \text{ m}^3/\text{cm} 
   \]
3. Pit volume equivalent to 33 cm of fluid
   \[ \text{Vol.} = 0,29 \text{ m}^3/\text{cm} \times 33 \text{ cm} = 9,57 \text{ m}^3 \]

**Tubulars**
Drill pipe, collars, casing, or tubing, used in a well, are referred to collectively as tubulars.
Total capacity and displacement of tubulars and annular volumes between the work string and the cased hole can be calculated using values given in tables.

**Example 6b**

**API**

**Given:** Tubular and well data of example workover

**Find:**
1. Tubular capacity (2-3/8 in - 4.7#/ft)
   - From tables: \( \text{Capacity} = .00387 \text{ bbl/ft} \)
   - \( 9050 \text{ ft} \times .00387 \text{ bbl/ft} = 35 \text{ bbl} \)

2. Capacity of tubing/casing annulus (7 in - 23# x 2-3/8 in) & (4-1/2 in - 11.6# x 2-3/8 in)
   - From tables: \( \text{Capacity} = .0339 \text{ bbl/ft (7")}; .0101 \text{ bbl/ft (4-1/2")} \)
   - \( 7150 \text{ ft} \times .0339 \text{ bbl/ft} = 242 \text{ bbl} \)
   - \( (9050 - 7150) \times .0101 \text{ bbl/ft} = 19 \text{ bbl} \)
   - Total = 261 bbl

3. Calculate capacity of casing (7 in - 23#) & liner (4-1/2 in - 11.6#)
   - From tables: \( \text{Capacity} = .0393 \text{ bbl/ft (7")}; .0155 \text{ bbl/ft (4-1/2")} \)
   - \( 7150 \text{ ft} \times .0393 \text{ bbl/ft} = 281 \text{ bbl} \)
   - \( (9100-7150) \times .0155 \text{ bbl/ft} = 30 \text{ bbl} \)
   - Total = 311 bbl

**SI**

**Given:** Tubular and well data of example workover

**Find:**
1. Tubular capacity (2-3/8 in - 4.7#/ft)
   - From tables: \( \text{Capacity} = 0,002019 \text{ m}^3/\text{m} \)
   - \( 2758,5 \text{ m} \times 0,002019 \text{ m}^3/\text{m} = 5,57 \text{ m}^3 \)

2. Capacity of tubing/casing annulus (7 in - 23# x 2-3/8 in) & (4-1/2 in - 11.6# x 2-3/8 in)
   - From tables: \( \text{Capacity} = 0,017679 \text{ m}^3/\text{m (7")}; 0,00525 \text{ m}^3/\text{m (4-1/2")} \)
   - \( 2180 \text{ m} \times 0,017679 \text{ m}^3/\text{m} = 38,54 \text{ m}^3 \)
   - \( (2758,5 \text{ m} - 2180 \text{ m}) \times 0,00525 \text{ m}^3/\text{m} = 3,04 \text{ m}^3 \)
   - Total = 41,58 m³

3. Calculate capacity of casing (7 in - 23#) & liner (4-1/2 in - 11.6#)
   - From tables: \( \text{Capacity} = 0,020538 \text{ m}^3/\text{m (7")}; 0,008108 \text{ m}^3/\text{m (4-1/2")} \)
Killing a producing well is often the first step in a workover operation. Prior to performing this step; however, certain actions must be taken to ensure the kill is performed in the safest and most efficient manner. These actions include shutting in the well, reading well pressures (tubing and annulus) and in general determining the current state of the well. With this done, kill calculations can be made and required kill methods and equipment selected.

Accepted oil field practice requires installation of a tubing plug about 100 feet down in the tubing and a back pressure valve in the bottom of the tree before rigging up required kill equipment. Thus if the tree leaks or is damaged during the rig-up process, there is no chance of a blowout. Immediately before beginning the kill, these two devices are removed to provide unobstructed flow through the tubing.

Kill equipment required other than the two devices mentioned, might include: kill lines, BOP’s for coil tubing or snubbing units, a “tree saver” and/or wireline equipment. Selection of this equipment is dependent, in part, on the pressures to be encountered during the kill.

Basic kill calculations require determination of the maximum expected kill pressures and the maximum allowable kill pressures. Example 7 illustrates a simple method for determining these pressures and ensuring that allowable pressures are not exceeded.

Example 7

Given: Perforations - 9100 ft Formation pressure - 5200 psi
Fracture gradient - .832 psi/ft Gas gradient - .087 psi/ft
Shut-in tubing pressure - 3700 psi Tubing - 2-3/8 in, 4.7#/ft, N-80
Find: Make necessary calculations to kill tubing in example well.

Solution for killing tubing side:
1. Determine kill fluid density (K.F.D.)
   \[ K.F.D. = \frac{5200 \text{ psi}}{.052 \times 9100 \text{ ft}} = 11.0 \]
   add .5 ppg trip margin and \[ K.F.D. = 11.5 \text{ ppg} \]
2. Determine fluid volume required to kill:
   Tubing = 9050 ft \times .00387 \text{ bbl/ft} = 35 \text{ bbl}
   Liner = 50 ft \times .0155 \text{ BBL/ft} = .75 \text{ BBL}
   Total capacity to kill tubing side = 36 BBL
3. Determine maximum allowable and expected static tubing pressures during kill:
   Formation fracture pressure = 7600 psi

   Maximum tubing pressures (MTP) during the kill must be determined assuming tubing is in communication with producing zone and contains a partial column of 9 ppg salt water.

   Well is shut-in and stabilized thus:
   Initial Maximum Tubing Pressure (IMTP)
When pumping is:

\[
\text{IMTP} = \text{FP} - \text{IHP} \\
\text{IHP} = \text{BHP} - \text{SITP} \\
\text{IMTP} = 7600 \text{ psi} - (5200 \text{ psi} - 3700 \text{ psi}) = 6100 \text{ psi}
\]

Note: (a) This pressure exceeds the 5,000 psi working pressure of the tree.
(b) This pressure drops as kill fluid is pumped into the well until the Final Maximum Tubing Pressure (FMTP) is reached at kill.

Final Maximum Tubing Pressure when pumping is:

\[
\text{FMTP} = \text{FP} - \text{FHP} = 7600 \text{ psi} - (0.052 \times 11.5 \text{ ppg}) \times 9100 \text{ ft} \\
= 7600 \text{ psi} - 5442 \text{ psi} = 2158 \text{ psi}
\]

4. Determine pump strokes and time to kill tubing at kill rate.

\[
\text{STR} = \frac{\text{Volume required}}{\text{Volume per stroke}} = 36 \text{ bbl} / .1328 \text{ bps} \\
= 271 \text{ strokes to kill} \\
\text{Time to kill at kill rate (40 spm) 5.3 BPM} = 271 /40 = 6.8 \text{ min} \\
\text{Excess kill fluid volume indicates the existence of some problem such as communication or gas migration.}
\]

5. Determine critical pump rate to prevent gas migration.

\[
\text{Gas migration rate (G.M.R.)} = 33 \text{ ft/min} \\
\text{Tubing capacity (T.C.)} = 258 \text{ ft/bbl} \\
\text{Critical pump rate} = \frac{\text{G.M.R.}}{\text{T.C.}} = 33 \text{ ft/min} / 258 \text{ ft/bbl} = .1289 \text{ bbl/min} \\
.128 \text{ bbl/min} / .1328 \text{ bbl/str} = .96 \text{ spm}
\]

\[
\text{SI}
\]

**Given:**
- Perforations – 2773.7 m
- Formation pressure – 35 866 kPa
- Fracture gradient – 18.85 kPa/m
- Gas gradient – 1.97 kPa/m
- Shut-in tubing pressure – 25 519 kPa
- Tubing - 2-3/8 in, 4.7#/ft, N-80

**Find:**
- Make necessary calculations to kill tubing in example well.

**Solution for killing tubing side:**

1. Determine kill fluid density (K.F.D.)

\[
\text{K.F.D.} = 35 866 \text{ kPa} / (0.00981 \times 2773.7) = 1318.6 \text{ kg/m}^3 \\
\text{add 60 kg/m}^3 \text{ trip margin and K.F.D.} = 1378.6 \text{ kg/m}^3
\]

2. Determine fluid volume required to kill:

\[
\text{Tubing} = 2758.44 \text{ m} \times 0.002019 \text{ m}^3/\text{m} = 5.57 \text{ m}^3 \\
\text{Liner} = 15.24 \text{ m} \times 0.008108 \text{ m}^3/\text{m} = 0.124 \text{ m}^3 \\
\text{Total capacity to kill tubing side} = 5.7 \text{ m}^3
\]

3. Determine maximum allowable and expected static tubing pressures during kill:

- Formation fracture pressure = 52 417 kPa
- Maximum tubing pressures (MTP) during the kill must be determined assuming tubing is
in communication with producing zone and contains a partial column of 1079 kg/m³ salt water.

Well is shut-in and stabilized thus:

Initial Maximum Tubing Pressure (IMTP)
When pumping is:

\[
\text{IMTP} = \text{FP} - \text{IHP}
\]
\[
\text{IHP} = \text{BHP} - \text{SITP}
\]
\[
\text{IMTP} = 52417 \text{ kPa} - (35866 \text{ kPa} - 25519 \text{ kPa}) = 42070 \text{ kPa}
\]

Note: (a) This pressure exceeds the 34485 kPa (5000 psi) working pressure of the tree.
(b) This pressure drops as kill fluid is pumped into the well until the Final Maximum Tubing Pressure (FMTP) is reached at kill.

Final Maximum Tubing Pressure when pumping is:

\[
\text{FMTP} = \text{FP} - \text{FHP} = 52417 \text{ kPa} - (0.00981 \times 1378.6 \text{ kg/m}^3 \times 2773.7 \text{ m})
\]
\[
= 14884 \text{ kPa}
\]

4. Determine pump strokes and time to kill tubing at kill rate.

\[
\text{STR} = \frac{\text{Volume required}}{\text{Volume per stroke}} = \frac{5.7 \text{ m}^3}{0.021 \text{ m}^3/\text{str}}
\]
\[
= 271 \text{ strokes to kill}
\]

Time to kill at kill rate (40 spm) 0.84 m³/min = 271 / 40 = 6.8 min

Excess kill fluid volume indicates the existence of some problem such as communication or gas migration.

5. Determine critical pump rate to prevent gas migration.

Gas migration rate (G.M.R.) = 10 m/min

Tubing capacity (T.C.) = 495.3 m/m³

Critical pump rate = G.M.R. / T.C. = 10 m/min / 495.3 m/m³ = 0.02 m³/min

0.02 m³/min / 0.021 m³/str = 0.96 str/min

Many considerations must be given to selecting the proper method of killing a normally pressured, producing well. Among these are the type of produced fluids, formation characteristics, tubing/casing integrity, and the ability to circulate. Most kill procedures can be placed in two categories: (1) those for killing through tubing with and without holes, and (2) for killing through the annulus. Concepts and procedures for killing an abnormally pressured, producing well are essentially the same as those for normally pressured wells. The primary difference is the use of high density kill fluids in place of 9.0 ppg brine water or other fluids of equal density.

Pressure limitations of the tree and burst pressures of the tubing and casing are usually a critical consideration with high pressure wells. Tubing holes and leaks become a very serious concern because the casing may be exposed to pressure. In addition, abnormal pressure wells often have additional problems such as corrosion and erosion that can seriously reduce pressure limitations of tubing and casing.
A Through Tubing Kill with no hole in the tubing is the most common in workover operations. Kill procedures for this situation include bullheading, use of coil tubing, snub jointed tubing, lubricating, perforate the tubing, and pulling the tubing out of the packer.

Bullheading is a term used to describe the pumping of the fluids into the formation. In the case of well control, the objective is to pump a workover fluid down the tubing and drive the formation fluids out of the tubing, through perforations and back into the formation.

It is important to note that pressures should decrease as the kill fluid is pumped into the well since the hydrostatic pressure of the kill fluid is greater than the formation fluid. If this occurrence is not observed to the extent expected in the field operations, either the formation's ability to accept the fluid is decreasing (plugging) or gas is migrating upward. It should also be noted that as the low density formation fluids are displaced by greater density brine fluids, the maximum surface-imposed, fracture pressures decrease.

Upward migration of low density fluids through higher density fluids may be a serious problem in workover operations, particularly when bullheading techniques are used. Factors affecting migration rates include (1) fluid densities and viscosities, (2) hole geometry, and (3) influx size. In the cases of formations with characteristics that only allow low pump-in rates, upward gas migration rates may equal or exceed the pump rates and result in negating the advantages of bullheading. The addition of viscosifiers to the workover fluid has been found to be a practical field-proven method to reduce migration rates. Gas migration will usually occur at the rate of 1000 feet per hour (305 meters per hour) in mud and 2000 feet per hour (310 meters per hour) in brine.

In some cases, bullheading may require that pressure be applied to the casing to prevent tubing burst. This technique is generally required when the pump-in pressure is high or when the tubing integrity is questionable due to erosion or corrosion. In these cases burst pressure of the casing is a very important consideration.

Formation fluids often affect the feasibility of bullheading procedures. Low viscosity fluids such as gas will flow back through the formation at rates sufficiently greater than oil or water. In addition, gas will have a reduced tendency to plug the formation as it reverses flow. Certain completion systems such as tubingless completions, however, may necessitate bullheading instead of some other alternative.

Coil Tubing is often used to kill a producing well. The objective is to circulate brine water down the small tubing and up the coil tubing - production tubing annulus. A primary application for coil tubing is in cases where the well cannot be killed by bullheading because the wellbore is plugged with sand or junk.

Applications for coil tubing may be restricted in gas wells due to strength limitations of the tubing. In some cases, field experience has shown that a coil tubing section filled with brine water will exceed the tensile strength of the pipe. This is not usually the case in oil wells because the buoyancy provided by the oil reduces the overall tubing load.

Snubbing units are frequently used for high pressure well control problems. Snubbing
small diameter pipe into tubing provides the same type of well control procedures as the coil tubing with the exception that additional time is required to snub in jointed pipe than continuous coiled tubing. The primary advantages of snubbing units over coil tubing are (1) the ability to rotate the jointed pipe and (2) the greater pipe strength characteristics.

**Lubrication** is occasionally used for killing wells during workover operations. It is a process that alternately pumps a kill fluid into the tubing or annulus, and then a volume of gas is allowed to escape from the well until the kill fluid begins to escape through the choke. At this point, brine water or other fluids are pumped into the tubing or annulus, and the cycle is restarted. As each volume of brine is pumped into the tubing, the SITP should decrease by a calculated value until the well is eventually killed. Caution must be exercised to insure that large volumes of kill fluids are not allowed to escape from the well during the bleeding phase.

The lubricate and bleed method is often employed to kill high pressure wells where kill pressures would approach the rated pressure of the wellhead or tubing and in wells that have a plugged wellbore or perforations and will not allow bullheading. Lubrication procedures can be employed to kill the well without necessitating the use of coil tubing or jointed concentric kill strings. It should be apparent, however, that lubrication is a time consuming process.

A certain amount of time is required for the gas to migrate upward through the falling kill fluid after the pumping ceases. gas migrates upward at 17-35 feet per minute; therefore after pumping, it is important to wait several minutes before bleeding gas from the well to prevent bleeding the kill fluid through the choke.

**Perforating the tubing** and circulating a kill fluid is another primary method of killing producing wells. The method utilizes a perforating tool to make a circulating port in the tubing that will allow direct circulation of brine water. In this situation, reverse circulation is usually employed by pumping down annulus, through the tubing perforation(s) and up the tubing. This method requires that the packer fluid in the annulus be in circulatable condition and not severely gelled or stratified.

Careful attention must be given to the selection of a perforation tool. It is important that the tool be capable of perforating the tubing without damaging the adjacent casing should the tubing be in close proximity to the casing. In addition, oriented perforating becomes a serious consideration in cases of multiple completions, which may have several tubing strings in the same casing annulus.

**Pulling the tubing out of the packer** to circulate a kill fluid out of the bottom of the tubing is a technique employed by many operators. This procedure involves lifting the tubing a sufficient height to pull the seal assembly from the polished bore in the packer. The disadvantage of this method is that it requires that of sections of the production tree be removed or un-flanged in order to pick up the tubing. Once the tree is un-flanged, the major blowout prevention tool has been altered.

Some types of completions are not suitable for this method of well killing. Tubing systems with long sections of seal assembly, completions with the packer screwed on to the tubing and tubingless completions, which do not employ a packer system, are examples. In these cases, the methods previously described must be used.
A through tubing kill with a hole in the tubing or a packer leak requires additional considerations. The primary concern is determining the location of the hole or leak. Additional concerns include (1) the effect of the formation pressure exposed on the casing and (2) the kill procedure that will be most effective in each case.

Determining the location of the tubing hole generally requires an on-site evaluation of the situation. The hole or leak will be indicated by pressure on the casing string(s). The most common method of locating the leak is by rigging surface equipment and pumping a volume of colored brine water until it is returned to the choke on the annulus. This volume can be used to calculate the location of the hole. Example 8 illustrates this procedure.

**Example 8**

**API**

**Given:** Casing is 7 inch, 23#/ft to 7150 ft; 4½ inch, 11.6#/ft to 9100 ft.
Packer set at 9050 ft.
Pressure on tubing/casing annulus.
Other data same as Example 7.

**Find:** Depth of leak if:

1. 40 barrels of kill fluid were circulated before being detected at the choke.
   Depth of leak = volume pumped / (tubing + annular capacity)
   From tables:
   Capacity of annulus = .0339 bbl/ft
   Capacity of tubing = .00387 bbl/ft
   Depth = 40 / (.0339 + .00387) = 40 / .038 = 1052 ft

2. 36 barrels of kill fluid were pumped and static pressure is zero but pressure is still on casing.
   Zero pressure on tubing indicates the tubing is full of kill fluid to the packer. Checking the volume required to fill the tubing can verify this. Pressure on the casing indicates a probable packer or casing leak.

**SI**

**Given:** Casing is 7 inch, 23#/ft to 7150 ft; 4½ inch, 11.6#/ft to 9100 ft.
Packer set at 2758,44 m.
Pressure on tubing/casing annulus.
Other data same as Example 7.

**Find:** Depth of leak if:

1. 6,35 cubic meters of kill fluid were circulated before being detected at the choke.
   Depth of leak = volume pumped / (tubing + annular capacity)
   From tables:
   Capacity of annulus = 0,017679 m³/m
   Capacity of tubing = 0,002019 m³/m
Depth = 6.35 / ((0.017679 + 0.002019) = 320.5 m

2. 5.7 cubic meters of kill fluid were pumped and static pressure is zero but pressure is still on casing.

Zero pressure on tubing indicates the tubing is full of kill fluid to the packer. Checking the volume required to fill the tubing can verify this. Pressure on the casing indicates a probable packer or casing leak.

Deep holes will generally allow the well to be killed in a conventional circulation manner. Shallow to medium depth holes will require snubbing coil tubing or jointed pipe or lubrication. Bullheading can be attempted only if the dynamic pressures do not exceed the casing burst pressures.

A separate annular kill is sometimes required because of a loss of integrity in the tubing string resulting from a hole or leak. In these cases, killing the tubing by lubricating or snubbing will not necessarily kill the annulus. It is therefore necessary to perform kill techniques on the annulus using one of the previously described methods. These include bullheading, lubricating, circulating or reverse circulating. Gas Migration can be a serious consideration when pumping down the annulus. Example 9 illustrates one method of killing a live annulus.

Example 9

API

1. Determine bottom hole pressure in the tubing at the circulating sub.
   BHP = \(0.052 \text{ psi/ft/ ppg} \times 11.5 \text{ ppg} \times 9020 \text{ ft.} = 5394 \text{ psi}\)

2. Open circulating sub and allow tubing and annulus pressures to equalize.
   No change on annulus - Tubing pressure increases from 0 to 800 psi

3. Determine BHP at the sub using new shut-in tubing pressure.
   BHP = 5394 psi + 800 psi = 6194 psi

4. Determine required density of kill fluid (KFD),
   KFD = \(6194 \text{ psi} / (0.052 \text{ psi/ft/ppg} \times 9020 \text{ ft}) = 13 \text{ ppg}\)
   Add trip margin of .5 ppg,
   KFD = 13 + .5 = 13.5 ppg

5. Begin pumping 13.5 ppg kill fluid down the tubing and simultaneously open the choke slowly. Maintain constant annulus pressure at the choke using the initial shut-in value (3700 psi) by adjusting the choke until the tubing is full of 13.5 fluid.

Tubing capacity to circulating sub:
   9020 ft x 0.00383 bbl/ft = 35 bbl
   At kill rate of 40 strokes per minute, time to fill tubing is about 7 minutes. Note that annulus pressure is the controlling factor at this point in the kill.

6. When tubing is full of 13.5 ppg kill fluid, continue pumping, holding tubing
pressure constant at the pressure observed by opening and closing the choke on the annulus. Also maintain pump rate constant. **Pump rate and pressure must be held constant throughout this phase of the kill.**

7. Capacity of 2 3/8" x 7" annulus = 7150 ft x .0339 bbl/ft = 242 bbls
   Capacity of 2 3/8" x 4½" annulus = (9020 ft - 7150 ft) x .0101 bbl/ft = 19 bbls
   Total capacity of annulus = 242 bbls + 19 bbls = 261 bbls

8. Pump Strokes to Kill (STK):
   \[ \text{STK} = \frac{\text{volume to kill}}{\text{volume per stroke}} = \frac{261 \text{ bbl}}{.1328 \text{ bbl/stk}} = 1965 \text{ strokes} \]
   If rate = 40 stk/min (5.3 bpm), time to kill is:
   \[ \text{Time} = \frac{261}{5.3} = 49 \text{ minutes}. \]

Remarks:

a. Tubing filling with 13.5 ppg fluid, circulating pressure about 1000 psi above shut-in. Note that with pump rate constant, circulating tubing pressure should be about 860 psi when the tubing is full. Static tubing pressure should be zero.

b. As kill fluid enters annulus, tubing pressure and rate should remain constant until kill is completed.

SI

1. Determine bottom hole pressure in the tubing at the circulating sub.
   \[ \text{BHP} = 0.00981 \times 1378.6 \text{ kg/m}^3 \times 2750 \text{ m} = 37190 \text{ kPa} \]

2. Open circulating sub and allow tubing and annulus pressures to equalize.
   No change on annulus - Tubing pressure increases from 0 to 5518 kPa

3. Determine BHP at the sub using new shut-in tubing pressure.
   \[ \text{BHP} = 37190 \text{ kPa} + 5518 \text{ kPa} = 42708 \text{ kPa} \]

4. Determine required density of kill fluid (KFD),
   \[ \text{KFD} = \frac{42708 \text{ kPa}}{(0.00981 \times 2750 \text{ m})} = 1583 \text{ kg/m}^3 \]
   Add trip margin of 60 kg/m³,
   \[ \text{KFD} = 1583 + 60 = 1643 \text{ kg/m}^3 \]

5. Begin pumping 1643 kg/m³ kill fluid down the tubing and simultaneously open the choke slowly. Maintain constant annulus pressure at the choke using the initial shut-in value (25 520 kPa) by adjusting the choke until the tubing is full of 1643 kg/m³ fluid.

   Tubing capacity to circulating sub:
   \[ 2750 \text{ m} \times 0.002019 \text{ m}^3/\text{m} = 5.55 \text{ m}^3 \]
   At kill rate of 40 strokes per minute, time to fill tubing is about 7 minutes. Note that annulus pressure is the controlling factor at this point in the kill.
6. When tubing is full of 1643 kg/m³ kill fluid, continue pumping, holding tubing pressure constant at the pressure observed by opening and closing the choke on the annulus. Also maintain pump rate constant. **Pump rate and pressure must be held constant throughout this phase of the kill.**

7. Capacity of 2 3/8" x 7" annulus = 2180 m x 0,017679 m³/m = 38,5 m³
   Capacity of 2 3/8" x 4½" annulus = (2750 m – 2180 m) x 0,00562 m³/m = 3,2 m³
   Total capacity of annulus = 38,5 m³ + 3,2 m³ = 41,7 m³

8. Pump Strokes to Kill (STR):
   STR = (volume to kill) / (volume per stroke) = 41,7 m³ / 0,0212 m³/str =
   = 1965 strokes
   If rate = 40 stk/min (0,848 m³/min), time to kill is:
   Time = 41,7 / 0,848 = 49 minutes.

Remarks:
   a. Tubing filling with 1643 kg/m³ fluid, circulating pressure about 6900 kPa above shut-in. Note that with pump rate constant, circulating tubing pressure should be about 5930 kPa when the tubing is full. Static tubing pressure should be zero.
   c. As kill fluid enters annulus, tubing pressure and rate should remain constant until kill is completed.

With the exception of bullheading and lubricating methods, killing a well requires circulating the kill fluid until all formation fluids are removed from the wellbore. Because of the significant pressure effects experienced, it is important that proper procedures be followed. Specific attention to these procedures will be covered following the discussion of shut-in considerations.

Pressure is the prime cause of well kicks. the two major causes of low hydrostatic pressure are insufficient mud weight and pressure effects while tripping.

**Mud weight insufficient** to balance exposed formation pressure is one of the main causes of a kick. As discussed, the hydrostatic pressure of the mud must be equal to or greater than the exposed formation's pressure. If the mud density is too low, an underbalance occurs and the well kicks.

This type of kick often occurs during workover when perforating new zones and when drilling through obstructions such as sand bridges or junk in the tubing or casing.

**Improperly filling the hole during trips** is another predominant cause of kicks. as the work string is pulled out of the hole, the fluid level will fall because each joint of the work string displaces some amount of mud. With the pipe no longer in the hole, the mud must fill the volume previously filled by the pipe. As the fluid level decreases, the hydrostatic pressure of the mud will also decrease. The following example illustrates the hydrostatic reduction when the drill pipe is pulled from the well.
Example 10
API

Calculate the hydrostatic pressure reduction when pulling 10 of 62-ft stands of tubing without filling the hole.

Well Data:  
- Casing: 7 inch, 23#/ft (6.366 in ID)  
- Work String: 2 3/8 inches, 4.7 #/ft  
- Mud Weight: 13.5 ppg

Displacement of 2 3/8", 4.7#/ft tubing = .068 gal/ft  
Displacement of 2 3/8", 4.7#/ft couplings = .057 gal/coupling  
Displacement of 2 3/8", 4.7#/ft upsets = .019 gal/upset  
1 Stand = 2 joints + 2 couplings + 4 upsets

Displacement = (62 ft/std x .068) + (2 couplings x .057) + (4 upsets x .019)  
= 4.2 gal/std + .113 gal/std + .076 gal/std  
= 4.4 gal/std

Displacement of 10 stands = 10 x 4.4 = 44 gallons  
Capacity of 7" 23#/ft casing = .6048 ft/gal  
Change in fluid level in 7" = .6048 x 44 = 26.6 ft  
Pressure gradient of 13.5 ppg WSF = .052 x 13.5 = .702 psi/ft  
Reduction in pressure = 26.6 x .072 = 19 psi

SI

Calculate the hydrostatic pressure reduction when pulling 10 of 18.9-m stands of tubing without filling the hole.

Well Data:  
- Casing: 7 inch, 23#/ft (6.366 in ID)  
- Work String: 2 3/8 inches, 4.7 #/ft  
- Mud Weight: 1618.7 kg/m³

Displacement of 2 3/8", 4.7#/ft tubing = 0.0008442 m³/m  
Displacement of 2 3/8", 4.7#/ft couplings = 0.0002157 m³/coupling  
Displacement of 2 3/8", 4.7#/ft upsets = 0.0000719 m³/upset  
1 Stand = 2 joints + 2 couplings + 4 upsets

Displacement = (18.9 m/std x 0.0008442) + (2 couplings x 0.0002157) + (4 upsets x 0.0000719)  
= 0.016 + 0.00043 + 0.00029 = 0.01672 m³  
Displacement of 10 stands = 10 x 0.01672 = 0.1672 m³  
Capacity of 7" 23#/ft casing = 0.020538 m³/m  
Change in fluid level in 7" = 0.1672 / 0.020538 = 8.14 m  
Pressure gradient of 1618.7 WSF = 0.00981 x 1618.7 = 15.9 kPa/m  
Reduction in pressure = 8.14 m x 15.9 kPa/m = 129.4 kPa
It should be obvious from this example that it is necessary to fill the hole with mud periodically to avoid sufficiently reducing the hydrostatic pressure and allowing a kick to occur. Several methods can be utilized to fill the hole, but all must be able to accurately measure the amount of required mud. The two methods most commonly used to monitor hole fill up are (1) a trip tank and (2) pump stroke measurement. Both of these devices were discussed in the equipment section of this manual. It is not satisfactory under any conditions to allow a centrifugal pump to continuously fill the hole from the suction pit since accurate mud volume measurement is not possible.

Killing a kick during workover operations requires a careful evaluation of the existing well conditions at the time of the kick. These include (1) tubing and casing pressures; (2) depth of the work string in the well, if any; (3) restrictions in the work string such as bit jets or circulating ports, and (4) well bore and formation characteristics that may affect circulation or alternate kill procedures such as bullheading or lubrication. Before a kick can be killed; however, it must be detected and the well shut-in. A knowledge of the causes and warning signs is very important to the workover crew. Although circulation is the most commonly employed kill procedure used during workover, other applicable methods include bullheading, lubricating and stripping into the well prior to circulating.

Kicks can be expected to occur whenever an underbalanced pressure condition exists in a well. An underbalance exists when the hydrostatic pressure of the well service fluid (WSF) in the well is less than the formation pressure acting against it. If the formation is permeable, gas, oil, or salt water will flow from the formation to the wellbore creating a “kick”. This influx of fluids will reduce the average density of the mud column, increasing the amount of underbalance. If uncontrolled, this cycle will continue until all of the WSF is displaced and formation fluids flow from the well. For this reason, even a short delay in implementing proper well control procedures can greatly increase the difficulty experienced in regaining well control.

Hydrostatic pressure has been identified as the primary means of maintaining well control during drilling and C, R&W operations. Conversely, low hydrostatic pressure is the primary cause of kicks. Since maintaining a full column of WSF is essential to maintaining control of the well, knowledge of the ways and means of keeping the hole full is essential to the rig crew.

Swab pressure is created by pulling the work string from the borehole. Swab pressure is a negative pressure, which reduces the effective hydrostatic pressure below the swab point. If this pressure reduction is large enough to lower the effective total hydrostatic pressure to a value below the formation pressure, a potential kick situation has been developed. Among the variables controlling swab pressures are (1) pipe pulling speed, (2) mud properties, (3) casing/hole size, and (4) the effect of large workover tools such as squeeze tools and packers.

In order to reduce the swab pressure, the pulling speed must be reduced.

It is important to remember that the swab pressure is added to the pressure reduction resulting from not keeping the hole full as pipe is pulled. In addition, the swab pressure is exerted at every point throughout the well below the work string. The most reliable method of detecting swabbing is proper hole filling.
Surge Pressures have been described as having an affect opposite to that of swab pressures. These pressures result from running into the well too fast with large tools on the work string. This can result in bottom hole pressure exceeding formation fracture pressure and subsequent loss of WSF to the formation. This mud loss, if not replenished, will lower the hydrostatic pressure of the WSF column and a kick can occur.

Workover operations such as logging, fishing, and testing can also result in a well kick. For this reason, constant vigilance is necessary during any workover procedure.

A number of warning signs can be observed at the surface immediately after a kick occurs. It is the responsibility of each crewmember to recognize and interpret these signs and to take the proper actions with respect to his well control duties. Although these signs do not positively identify a kick, they do warn of a potential kick situation.

1. An increase in the flow rate leaving the well while pumping at a constant rate is a primary kick indicator. The increased flow rate is interpreted to mean that the formation is aiding the rig pumps in moving the fluid up the annulus by forcing fluids into the wellbore.
2. A continued flow from the well when the rig pumps are not moving the mud indicates that a kick is in progress. An exception to this occurs when the mud in the drill pipe is considerably heavier than that in the annulus as in the case of a slug.
3. A pump pressure change may indicate a kick. Initial entry of formation fluid into the well may cause the mud to flocculate and temporarily increase the pump pressure. As flow continues, the low density influx will displace the heavier drilling fluids, and the pump pressure may begin to decrease. As the effective hydrostatic pressure in the annulus becomes less, the WSF in the work string may fall, resulting in an increase in pump speed.

No single indicator should be used alone as other problems may exhibit these same signs. A hole in the pipe, called a washout, will cause the pump pressure to decrease, and a twist-off of some portion of the drill string will have the same signs. It is the proper procedure, however, to check for a kick if these signs are observed.

4. Unexpected changes or lack of expected changes in pit volume are indications of a kick or perhaps lost circulation, which could result in a kick. If, on tripping out, the well does not take the calculated amount of fluid, the reason is probably an influx of formation fluid. Conversely, a gain in total pit volume at the surface, assuming no WSF materials are being added at the surface, indicates either an influx of formation fluids into the wellbore or the expansion of gas in the hole. Fluid influx at the bottom of the hole shows an immediate gain of surface volume due to the incompressibility of a fluid, i.e., a barrel in at the bottom pushes out an extra barrel at the surface. The influx of a barrel of gas will also push out a barrel of WSF at the surface, but as the gas approaches the surface, an additional increase in pit level will occur due to gas expansion.
5. A final indicator is a sudden change in weight of the work string. Such a change can be an indicator of several problems; however, it will result from an influx of formation fluid, which is of density significantly different from that of the mud. Because of the relatively large density differences required, this indicator usually has more application to drilling than to C, R&W operations.

Shut-in Procedures vary with operators and well conditions, however, some procedures are common because of their relative advantages. Regardless of the operator, basic accepted
practice requires that upon recognition of kick warning signs, operations in progress should be stopped and the kelly and first connection picked up above the rotary table. Raising the kelly is an important procedure for several reasons. With the kelly out of the hole, the valve at the bottom of the kelly can be closed if necessary. In addition, the annular preventor members can attain a more secure seal on pipe than a kelly. If the well is being circulated, the pumps should be turned off and conditions allowed to stabilize. If the well continues to flow, it should be shut-in by closing a BOP and diverting the flow through an open choke. The choke should then be closed. This is referred to as a "soft" shut-in. Tubing and casing pressures and pit gain should then be read and recorded. Some industry personnel believe the "soft" shut-in procedure allows too long a time to elapse before the well is shut-in. They, therefore, advocate use of an alternate procedure referred to as a "hard" shut-in. This involves closing the BOP with the choke already closed. Regardless of the procedure used, the objective is to shut-in the well as quickly as possible to reduce the size of influx. Under no circumstances should the pipe be run back to bottom with the annular BOP open and the well flowing!

Most blowout situations (kick) occur when the pipe is off bottom, such as while tripping or working the string. If the kelly is not made up on the work string when a kick is detected, a full opening safety valve should be installed. Installing a full opening (TIW) safety valve in preference to an inside blowout preventor (float) valve is a prime consideration because of the advantages offered by the full opening valve. If flow is encountered up the work string as a result of a trip kick, the fully opened, full opening valve is physically easier to stab on the pipe than a float type inside blowout preventor valve which would automatically close when the upward moving fluid contacts the valve. Also, if wireline work such as perforating or logging becomes necessary, the full opening valve will accept logging tools approximately equal to its inner diameter, whereas the float valve prohibits wireline work altogether. After the kick is shut-in, an inside blowout preventor float valve may be stabbed on top of the full opening valve to allow stripping operations for the return to bottom.

Shut-in procedures are then of two basic types (1) those used with the kelly made up and (2) those used while tripping. To summarize:

1. Shut-in procedures with the kelly made up:
   a. When a primary warning sign of a kick has been observed, immediately raise the kelly until a connection is above the rotary table.
   b. Stop the mud pumps and observe well for flow.
   c. If the well is flowing, close the annular preventor and close the choke.
   d. If the well is not flowing, resume operations.
   e. Notify the company personnel.
   f. Read and record the shut-in tubing pressure, the shut-in casing pressure, and the pit gain.

2. Shut-in procedures while tripping:
   a. When a primary warning sign of a kick has been observed, immediately set the top connection on the slips and observe for flow.
   b. Install and make up a fully opened TIW valve in the work string.
   c. Close the TIW valve and the annular preventor.
   d. Close the choke.
   e. Notify the company personnel.
   f. Pick up and make up the kelly.
g. Open the safety valve.
h. Read and record the shut-in tubing pressure, the shut-in casing pressure, and the pit gain.

Pressure effects of a kick, both at the surface and down hole, are dependent upon the amount of underbalance at the time of the kick, the size of the influx, the density of the influx fluid, location of the influx point and whether the influx was liquid or gas.

At the surface, shut-in tubing and casing pressures both reflect the difference between formation and hydrostatic pressures. Both are affected by the amount of underbalance following the relationship: the greater the underbalance the greater will be the surface pressures. Normally shut-in casing pressure is higher than shut-in tubing pressure because the "kick fluid" usually enters only the annulus. This is the result of a lower total hydrostatic pressure in the annulus than the tubing.

As discussed, the difference in hydrostatic pressures between annulus and tubing is the result of volume (height) of the influx, its density and whether any influx fluid entered the tubing. However, if the density of the influx fluid is close to the density of the WSF, little difference in tubing and annulus shut-in pressures will be observed. Equation 6 shows the relationship between these variables.

**Equation 6**

**API**

\[
\text{SICP} = FmP - 0.052 \times (L_m d_m + L_i d_i)
\]

where

- \( SICP = \) Shut-in casing pressure
- \( L_m = \) Length of the mud column
- \( d_m = \) Density of mud
- \( L_i = \) Length of influx
- \( d_i = \) Density of influx
- \( FmP = \) Formation Pressure

**SI**

\[
\text{SICP} = FmP - 0.00981 \times (L_m d_m + L_i d_i)
\]

where

- \( SICP = \) Shut-in casing pressure
- \( L_m = \) Length of the mud column
- \( d_m = \) Density of mud
- \( L_i = \) Length of influx
- \( d_i = \) Density of influx
- \( FmP = \) Formation Pressure

This equation applies to both shut-in casing and shut-in tubing pressures.

If all of the influx is confined to the tubing/casing annulus, the shut-in tubing pressure (SITP) is:
Equation 7

API

\[ \text{SITP} = F_m P - 0.052 \times (D_w)(d_m) \]

where \( D_w \) = total well depth

SI

\[ \text{SITP} = F_m P - 0.00981 \times (D_w)(d_m) \]

where \( D_w \) = total well depth

If the work string is off bottom and all the influx is below the bottom of the work string, no pressure difference between SICP and SITP will be observed. Also, if there is a hole in the tubing and all of the influx is trapped below the hole, the two pressures will read the same. In these cases Eq. 6 applies directly.

A final pressure effect, which may be of concern, is called a pressure pulse, sometimes called "water hammer" effect. These pressure pulses are transmitted internally through the WSF from surface to bottom of the hole and back. They result from quickly shutting in the well; however, there is some disagreement as to the actual affect these pulses have on the well.

The likelihood of extreme pulses is probably much less when shutting-in with an annular-type preventor and/or when the influx contains a high percentage of gas. Also, if the BOP is closed with the choke line and choke open and final closure is made with the choke, pressure pulses are unlikely. This shut-in procedure takes a little longer, and a larger influx can occur. However, it also has the advantage of allowing casing pressure to be monitored during closure. Thus, if the pressure becomes excessive, a decision can be made not to shut-in the well completely and to follow the Low Choke Pressure method of killing the well.

Down hole pressure effects are greater than those at the surface. As stated, influx size and density determine them. Down hole pressures are the result of adding surface and hydrostatic pressures in a static system. In a dynamic system, pressure losses due to flowing friction must also be considered.

For a kick, shutting in a well creates a static system, thus limiting pressure components to only surface and hydrostatic. This allows easy calculation of kill mud weights. These pressures must then be analyzed in relation to well conditions.

The final effect of reduced annular hydrostatic pressure will be an increase in the closed-in casing pressure. Since pressures in the annulus are additive, all wellbore pressures from surface to the top of the influx will also be larger. Higher closed-in casing pressures can cause formation breakdown in this instance, just as in the situation previously discussed when closing-in with a large underbalance. In order to decrease the likelihood of excessive down hole pressured, early detection and quick closure of BOP’s are essential.

Equation 8 shows the relationship of bottomhole pressure to the influx parameters discussed.
Equation 8

API

\[ BHP = FmP = SICP + HP_a = SITP + HP_t \]

where \( HP_a \) = Hydrostatic Pressure in Annulus
\[ = 0.052 \left( L_{md} + L_{id} \right) \]
\( HP_t \) = Hydrostatic Pressure in Tubing
\[ = 0.052 L_{md} \text{ (for tubing on bottom)} \]

SI

\[ BHP = FmP = SICP + HP_a = SITP + HP_t \]

where \( HP_a \) = Hydrostatic Pressure in Annulus
\[ = 0.00981 \times (L_{md} + L_{id}) \]
\( HP_t \) = Hydrostatic Pressure in Tubing
\[ = 0.00981 \times L_{md} \text{ (for tubing on bottom)} \]

Example 11 (workover problem)

API

Kick Data: \( SITP = SICP = 350 \text{ psi} \)
1. Actual Underbalance = .5 ppg
2. Effective Underbalance = .5 ppg
3. Occurs in 4½" casing below packer
4. Well pressure (after shut-in) with surface pressure stabilized:
   \[ BHP = FmP \]
Find Size of Influx (\( L_i \)) & (\( V_i \))
1. Actual Underbalance (11 ppg WSF)
   \[ SICP = FmP - Gill - (0.052)(d_m)(D-L_i) \]
   \[ 350 \text{ psi} = 5200 \text{ psi} - (0.052)(11 \text{ ppg})(9100 - L_i) \]
   \[ 350 = 5200 + 0.572 L_i - (572)(9100) \]
   \[ .572 L_i = 355 \]
   \[ L_i = 620 \text{ ft} \]

Kick is below tubing, capacity of 4½", 11.6 #/ft casing:
\[ V_i = 620 \text{ ft} \times 0.0155 = 9.6 \text{ bbl} \]

2. Effective Underbalance (11.5 ppg WSF)
\[ SICP = FmP - Gill - (0.052)(d_m)(D-L_i) \]
\[ 350 \text{ psi} = 5200 \text{ psi} - (0.052)(11.5 \text{ ppg})(9100 - L_i) \]
\[ 350 = 5200 + 0.598 L_i - 5442 \text{ psi} \]
\[ .598 L_i = 592 \]
\[ L_i = 990 \text{ ft} \]
\[ V_i = 990 \text{ ft} \times 0.0155 = 15.3 \text{ bbl} \]

SI

Kick Data: \( SITP = SICP = 2414 \text{ kPa} \)
1. Actual Underbalance = 60 kg/m³

\[ FmP \]

350 psi = 2774 kPa
2. Effective Underbalance = 60 kg/m³

3. Occurs in 4½" casing below packer

4. Well pressure (after shut-in) with surface pressure stabilized:
   \[ \text{BHP} = \text{FmP} \]

Find Size of Influx (\(L_i\)) & (\(V_i\))

1. Actual Underbalance (1319 kg/m³ WSF)
   \[ \text{SICP} = \text{FmP} - \text{GIlI} - 0.00981 \times d_m \times (D-L_i) \]
   \[ 2414 \text{ kPa} = 35864.4 \text{ kPa} - 0.00981 \times 1319 \text{ kg/m³} \times (2774 \text{ m} - L_i) \]
   \[ 2414 \text{ kPa} = 35864.4 \text{ kPa} + 12.94 \times L_i - 12.94 \times 2774 \text{ m} \]
   \[ 12.94 \times L_i = 2445 \]
   \[ L_i = 189 \text{ m} \]

   Kick is below tubing, capacity of 4½", 11.6 #/ft casing:
   \[ V_i = 189 \text{ m} \times 0.008108 \text{ m}^3/\text{m} = 1.53 \text{ m}^3 \]

2. Effective Underbalance (1379 kg/m³ WSF)
   \[ 2414 \text{ kPa} = 35864 \text{ kPa} - 0.00981 \times 1379 \text{ kg/m³} \times (2774 \text{ m} - L_i) \]
   \[ 2414 \text{ kPa} = 35864 + 13.5 \times L_i - 37449 \]
   \[ 13.5 \times L_i = 4000 \]
   \[ L_i = 296 \text{ m} \]
   \[ V_i = 296 \text{ m} \times 0.008108 \text{ m}^3/\text{m} = 2.4 \text{ m}^3 \]

Care should be exercised when reading shut-in pressures to ensure their accuracy. Trapped pressure or the use of a float valve can adversely affect kill calculations.

Trapped pressure can cause errors in interpreting the shut-in pressures. This type of pressure is defined as any pressure recorded on the tubing or casing that is more than the amount needed to balance the bottomhole pressure. Pressure can be trapped in the system in several ways, but the most common are (1) gas migrating up the annulus and (2) shut-in of the well before the mud pumps have quit pumping. It should be obvious that if a pressure reading that contains some amount of trapped pressure is used, the calculations necessary to kill the well will be in error. A simple procedure to use when checking for trapped pressure is given below for reference.

**PROCEDURE WHEN CHECKING FOR TRAPPED PRESSURE**

1. When checking for trapped pressure, bleed from the casing side only. the reasons are (1) the primary choke is generally located on the casing side, (2) to avoid contamination of the mud ( or brine water ) in the work string ( tubing ), and (3) to avoid the possibility of plugging the jets of the bit, circulating port, or sliding sleeve.
2. Use the work string pressure as a guide since it is a direct bottomhole pressure indicator.
3. Bleed small amounts (1/4 to 1/2 barrels) of mud at a time. Close the choke after bleeding and observe the pressure on the work string.
4. Continue to alternate the bleeding and subsequent pressure observation procedures as long as the shut-in work string pressure continues to decrease. When the
pressure ceases to fall, stop bleeding and record the true SITP and SICP.

5. If the SITP should decrease to zero during this procedure, continue to bleed and check pressures on the casing side as long as the casing pressure decreases.

(Note: This step will normally not be necessary.)

The basis for this procedure is that trapped pressure is more than the amount needed to balance the bottomhole pressure and it can be bled off without allowing any additional influx into the well. However, after all of the trapped pressure is bled off, continued bleeding will allow more influx into the well and the surface pressures will begin to increase.

These bleeding procedures can be implemented at any time. However, it is advisable to check for trapped pressure when the well is initially shut-in and to recheck when the work string is displaced with a clean kill fluid if any pressure remains on the work string.

Occasionally, kick killing procedures must be implemented when a tubing float valve is used. Since a float valve prevents fluid and pressure movement up the work string, there will be no pressure indicated on the tubing after the well is shut-in. Several procedures for determining the tubing pressure (SITP) are available with each being dependent on the amount of information known at the time the kick occurs. Because float valves are seldom used on workovers, these procedures are not addressed here.

Crew Member Responsibilities for shut-in procedures are important and must be assigned before beginning any C,R&W operation.

Kill Mud Weight Calculations must be made subsequent to well shut-in to determine the fluid density, which will create a hydrostatic pressure equal to or greater than formation pressure. Kill mud weight is defined as the fluid density necessary to exactly balance bottomhole formation pressure. It will provide the required controlling pressures yet minimize the possibility of casing burst or formation fracture.

Equations 9 or 10 can be used to calculate the required kill mud density.

**Equations 9 and 10**

**API**

\[
KMW = \frac{(SITP + THP)}{(0.052 \times TVD)} \quad \text{Eq. 9} \\
= \frac{BHP}{(0.052 \times TVD)} \quad \text{Eq. 10}
\]

Where:

- **KMW** = Kill mud weight, ppg
- **SITP** = Shut-in tubing pressure, psi
- **TVD** = True vertical depth, feet
- **.052** = Conversion constant, psi/ft/ppg
- **THP** = Tubing hydrostatic pressure, psi
- **BHP** = Bottom hole pressure, psi

**SI**

\[
KMW = \frac{(SITP + THP)}{(0.00981 \times TVD)} \quad \text{Eq. 9} \\
= \frac{BHP}{(0.00981 \times TVD)} \quad \text{Eq. 10}
\]
Where:
- KMW = Kill mud weight, kg/m³
- SITP = Shut-in tubing pressure, kPa
- TVD = True vertical depth, m
- 0.00981 = Conversion constant
- THP = Tubing hydrostatic pressure, kPa
- BHP = Bottom hole pressure, kPa

**Example 12**

**API**

**Problem:** Well has kicked while tripping with tubing at depth of 7376 ft.
**Given:** Data from Example Workover
- Perforation - 9100 ft.
- SITP - 350 psi
- WSF Density - 11.5 ppg
- Influx Volume = 15.3 bbl

**Find:** Kill Mud Weight to Kill at Current Depth (Dₜ)

\[ F_mP = \frac{0.052 \times (KMW) \times D_1}{5200 \text{ psi}} \]
\[ = \frac{0.052 \times (KMW) \times 7376 \text{ ft}}{5200 \text{ psi}} \]
\[ = 13.5 \text{ ppg} \]

T.M. = .5 ppg
Final KMW = 14 ppg

**SI**

**Problem:** Well has kicked while tripping with tubing at depth of 2248 m.
**Given:** Data from Example Workover
- Perforation – 2774 m
- SITP – 2414 kPa
- WSF Density – 1379 kg/m³
- Influx Volume = 2,43 m³

**Find:** Kill Mud Weight to Kill at Current Depth (Dₜ)

\[ F_mP = \frac{0.00981 \times (KMW) \times D_1}{35864.4 \text{ kPa}} \]
\[ = \frac{0.00981 \times (KMW) \times 2248 \text{ m}}{35864.4 \text{ kPa}} \]
\[ = 1626 \text{ kg/m}^3 \]

T.M. = 60 kg/m³
Final KMW = 1686 kg/m³

When the work string is near the bottom of the well, circulating out the kick with a kill fluid is the approach most often used. The surface equipment employed in the procedure includes the pumps and a choke to apply a back pressure during the operation. The kill fluid is usually fresh or brine water but will occasionally be a weighted fluid such as calcium bromide or heavy mud. The circulation route can be (1) the long way, which requires pumping down the work string and up the annulus or (2) the short way (reverse-out) which requires pumping down the annulus and
The long or regular method of circulation involves pumping a kill fluid down the tubing or work string and up the annulus, displacing the kick fluids during the circulation. The primary advantage of this method is (1) kill pressures are lower than with the reverse-out procedure and (2) gas migration is not often a severe problem with this procedure.

In most cases, the kill fluid will be about 9.0 ppg (1080 kg/m³) brine water since formations generally encountered are normally pressured or depleted. Higher kill mud weights are required as in the cases of (1) abnormal formation pressures or (2) wellbore obstructions, which prevent running the work string to the bottom of the well.

Circulating kill fluids will cause the tubing pressures to change during the actual operations. Causes of the changes include (1) dynamic pumping pressures, (2) gas in the tubing, (3) displacing low density workover fluids with high density kill mud, and (4) effects of the choke restriction.

The basis of all kill procedures requires maintaining the pumping pressure at predetermined levels. Accepted practice requires that bottomhole pressure be kept constant while pumping to maintain it at a value slightly greater than formation pressure. The choke, which is a pressure control tool, is used to raise or lower the pumping pressure to the level required to maintain constant bottom hole pressure.

In the event that a high density kill fluid is required to kill the kick, a kill sheet may become necessary to aid in determining the proper amounts of pressure to maintained on the pump. The kill sheet is used to calculate (1) kill fluid densities, (2) expected pressure changes on the pumping pressures, and (3) other required items such as work string volumes during the kill operation.

The annulus pressure will also experience many changes during the course of the kick killing procedures. The changes result from (1) gas expansion, (2) gas migration, (3) choke changes, and (4) high kill mud weights when used. It should be noted that the primary objective during the kick killing exercise is maintenance of the required pumping pressures by adjusting the casing pressure as necessary.

Reverse circulation involves pumping kill fluids down the annulus and displacing the kick fluids up the tubing. This procedure requires that a choke is placed in the standpipe or that the surface equipment can be arranged in such a manner that conducts the kick fluids through the standpipe to the choke. The reverse circulation method utilizes the pumping casing pressure to monitor the kill operation. The standpipe choke is used to adjust the pumping casing pressure to the required values.

Reverse circulation offers several advantages and disadvantages relative to normal circulation. The advantages include (1) a significant reduction in the time required to circulate the kick fluid from the well, and (2) better control of high surface pressures due to the generally greater burst strength of tubing and work strings as compared to casing. The disadvantages of the reverse circulation procedure include (1) possible plugging when attempting to reverse flow if bit jets or circulating ports are in the work string and (2) the slow circulating rates used in the reverse procedure may allow gas to migrate up the annulus at a rate greater than the downward
flow rate. Reverse circulation kills are not as often used as normal circulation. This in not necessarily true for high pressure wells, however.

Three Constant Bottomhole Pressure Methods are widely used when killing a well. Each procedure is designed to remove the kick fluid from the bore-hole and to establish sufficient hydrostatic pressure to dominate the reservoir while maintaining constant bottomhole pressure. These methods are:

1. Driller's Method
2. Wait and Weight Method
3. Concurrent Method

In each of these methods, the bottomhole pressure is held constant by adjusting the choke according to the drill pipe pressure. With each of these methods, it is desirable to measure circulating system pressure losses at a reduced rate, called the kill rate, prior to taking a kick. Normally, this pressure loss is measured at one half the normal circulating rate. The test should be made at least once a tour, or when WSF density is adjusted, and should be recorded on the driller's tour sheet. Delta prefers the first two of these kill methods for use when drilling. The method selected for use during both drilling and workover operations will depend on the well condition at that time.

The Driller's Method of well killing requires two separate circulations of the well. The first circulation is required to remove the formation fluids from the annulus using the mud density in the hole at the time of the kick. Drill pipe pressure is held constant by choke manipulation after start-up at the level required to maintain bottomhole pressure equal to, or slightly greater than, formation pressure. The pump rate is held constant at the predetermined reduced rate. If the kick contains gas, it will expand in the annulus under controlled conditions as it nears the surface. Therefore an increase in casing pressure and pit volume should be expected. Drill pipe pressure and pump rate must be held constant. At any time during or immediately after this first circulation, the well can be shut-in and the drill pipe pressure will read the same as it did originally.

After the kick fluid has cleared the choke, the well can be closed in. At this time, shut-in drill pipe and casing pressures will be the same, assuming all kick fluid has been removed and mud hydrostatic is the same inside the drill pipe and in the annulus. The original closed-in drill pipe pressure is converted to an equivalent density at the bit, and the mud density increased accordingly.

During the second circulation, bottomhole pressure is held constant by first controlling casing pressure equal to the shut-in value while filling the tubing with the weighted mud. When the tubing is filled, as determined by the number of strokes pumped or time, the tubing pressure is recorded and control shifts to a constant tubing pressure while the annulus is filled with heavy mud. When the heavy mud reaches the surface the pressure on the choke should be minimal. The pumps should be stopped and the well checked for flow. The well should be dead. Normally, more than one circulation is made for each step of the Driller's Method to ensure uniform distribution of mud density throughout the system.

Any time a well under pressure is circulated, the start-up procedure is critical and should be done with exceptional care. The closed-in casing pressure should be held by choke manipulation as the pump is slowly brought up to kill speed. This ensures that bottomhole
pressure remains constant. After the proper kill speed is attained, control is shifted to the tubing pressure. This procedure is valid because casing pressure should be the same whether the well is closed-in or being pumped. However, the tubing pressure must vary depending upon the circulating pressure loss in the system. The casing pressure cannot be held constant very long due to the changing length of the kick fluid.

The Wait and Weight Method of well killing theoretically requires only one complete circulation. The fully weighted mud is circulated at the same time the kick fluid is removed from the annulus. After the well has been properly shut in, the pressures recorded, and pit volume increase recorded, mud density is increased in the pits and a drill pipe pressure schedule established.

A schedule or chart must be prepared in order that drill pipe/tubing pressure can be properly adjusted downward as heavy mud fills the drill pipe. Once the heavy mud turns the corner (reaches bottom), the drill pipe pressure should be held constant until the heavy mud reaches the surface. Bottomhole pressure will be equal to, or slightly greater than, formation pressure throughout the procedure as long as pump rate is maintained at the predetermined rate.

If the kick contains gas, it will expand in the annulus, under controlled conditions, as it nears the surface. Therefore, an increase in casing pressure and pit volume should be expected. However, drill pipe pressure and pump rate must be held at the predetermined level.

The start-up procedure is as critical in the Wait and Weight Method as in the Driller's Method. In order to prevent loss of circulation and/or an additional flow, the pump should be brought up to kill speed with the casing pressure held at the closed-in value by adjusting the choke. After kill speed is reached, the drill pipe schedule should be followed using a constant pump speed.

Often more than one complete circulation is required to remove the kick fluid and properly balance mud hydrostatic inside the drill pipe and in the annulus. A check of the pressures can be made by shutting down the pump and reading the shut-in drill pipe and casing pressures. If both do not read zero, additional circulation will be required.

In summary, the Wait and Weight Method provides a constant bottomhole pressure equal to or slightly greater than formation pressure. This is accomplished by using a constant pump speed and adjusting the drill pipe pressure by choke manipulation. Drill pipe pressure is adjusted downward according to a predetermined schedule as the weighted mud fills the drill pipe and is held constant as the weighted mud fills the annulus. Weighted mud is being pumped at the same time the kick fluid is circulated from the annulus.

Each method provides relative advantages and disadvantages, depending upon the general conditions of the area of operation or the specific conditions in the subject well. The choice of method is made by the operator's representative or by local policy. Overall, the Wait and Weight Method provides the best combination of benefits for both onshore and offshore operations. The following shows the relative advantages and disadvantages for each method.
<table>
<thead>
<tr>
<th>Method</th>
<th>Advantages</th>
<th>Disadvantages</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Drillers</strong></td>
<td>1. Simplicity, i.e., few calculations, no charts.</td>
<td>1. Requires two circulations.</td>
</tr>
<tr>
<td></td>
<td>2. Clear intrusion quickly, reducing chance of sticking and kick migration</td>
<td>2. Highest casing and casing seat pressure.</td>
</tr>
<tr>
<td></td>
<td>3. Can be used until barite arrives.</td>
<td>3. Highest lost circulation potential.</td>
</tr>
<tr>
<td><strong>Wait and Weight</strong></td>
<td>1. Lowest casing and casing seat pressure.</td>
<td>1. Stuck pipe and kick migration potential.</td>
</tr>
<tr>
<td></td>
<td>2. Lowest lost circulation potential.</td>
<td>2. Requires a drill pipe schedule or graph.</td>
</tr>
<tr>
<td></td>
<td>3. One circulation required.</td>
<td></td>
</tr>
</tbody>
</table>

During C, R&W operations the well is usually fully cased and the pressure of the exposed reservoir is known. The WSF is, therefore, probably already of sufficient density to control the formation. In these cases, the kick will usually be the result of an effective underbalance created by swabbing. Thus, the WSF need not be weighted up as long as the tubing is sufficiently close to bottom. The kill method used is then equivalent to the Drillers Method, with the exception that only one circulation is required since the "weight up" is unnecessary.

Should the above condition occur when the tubing is sufficiently off bottom to preclude control without snubbing to bottom, it may be necessary to "weight up" the WSF in order to accomplish the kill from the shallower depth, The kill method used is then equivalent to the Wait and Weight method since the first circulation of the WSF would not change the fluid density above the kick.

The C,R&W supervisor should be aware that the conditions and kill methods described above may change when the influx enters the tubing/casing annulus. As an example, if using the Wait and Weight Method, it may be necessary to convert to the Drillers Method when the influx enters the annulus because of increased annulus pressures.

In all methods of well control, it is important to maintain a constant pump speed along with the required casing or tubing pressure. If the pump speed is allowed to change or the proper surface pressure not used, bottomhole pressure will be either too high or too low and either loss of circulation or additional influx will occur. If the kill rate must be changed, a new tubing
pressure schedule which accounts for a change in the circulating pressure losses must be followed.

During the shut-in period, the tubing and casing pressures may rise, depending upon the presence of influx gas in the annulus and the amount of percolation. These pressures should be bled through the choke so that original shut-in tubing pressure is restored. If this procedure is not followed, wellbore pressures will be excessive.

The selection of the proper well control method depends mostly on the situation on the rig at the time of the kick, the familiarity with the various methods and experience of the man in charge, and company or government policy for the particular area. It would be wise to completely understand each of the various constant bottomhole pressure methods.

Equally important as the complete understanding of the well control methods, is the ability of the crew to detect a kick early and to close in the well properly. Early detection, proper well closure and the implementation of a constant bottomhole pressure method of well control can reduce tremendously the possibility that the kick will develop into a blowout.