WELL CONTROL REFERENCE GUIDE
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Introduction
This handbook contains a variety of well control topics for field and office based drilling, workover, production and service personnel.
It is intended to be a quick reference guide and not a detailed engineering planning tool.
The handbook is a mix of the following content:
- Charts
- Tables
- Calculations
- Narrative and descriptions
- Rules of Thumb
- Best practices
References are given throughout the handbook so the user can dig deeper into the underlying principles if desired.

Categories
The topics are grouped together in categories.
- Conventional well control issues make up the majority of the handbook. These subjects are ones that are commonly encountered during the normal course of drilling, completion, workover and production operations.
- Special services such as hot tap and freeze operations are briefly outlined so the user can be familiar with the special nature of these types of interventions if the need arises.
- Blowout topics are included for informational purposes. These matters are intended to be a reference for a variety of blowout intervention actions.

Users are encouraged to contact Blowout Engineers for discussion or corrections on any item in this handbook.

This handbook is available in the following formats:
- Hard copy tally book insert
- PDF version from www.blowoutengineers.com

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Abbreviations and Acronyms

The following abbreviated terms with associated units are used throughout this reference guide unless otherwise stated for specific formulas.

<table>
<thead>
<tr>
<th>Term</th>
<th>Description</th>
<th>Unit</th>
</tr>
</thead>
<tbody>
<tr>
<td>ACF</td>
<td>Annulus Capacity Factor</td>
<td>bbl/ft</td>
</tr>
<tr>
<td>bbl</td>
<td>Barrel</td>
<td>bbl</td>
</tr>
<tr>
<td>BHP</td>
<td>Bottom-hole Pressure</td>
<td>psi</td>
</tr>
<tr>
<td>BOP</td>
<td>Blowout Preventer</td>
<td></td>
</tr>
<tr>
<td>Cap</td>
<td>Capacity</td>
<td>bbl/ft</td>
</tr>
<tr>
<td>CF</td>
<td>Capacity Factor</td>
<td>bbl/ft</td>
</tr>
<tr>
<td>$c_f$</td>
<td>Compressibility Factor</td>
<td>ppg/1000 psi</td>
</tr>
<tr>
<td>$C_{FP}$</td>
<td>Free-point Constant</td>
<td></td>
</tr>
<tr>
<td>csg</td>
<td>Casing</td>
<td></td>
</tr>
<tr>
<td>$d_{avg}$</td>
<td>Average Density</td>
<td>ppg</td>
</tr>
<tr>
<td>Dsurf</td>
<td>Surface Density</td>
<td>ppg</td>
</tr>
<tr>
<td>Dis Vol</td>
<td>Displacement Volume</td>
<td>bbl/ft</td>
</tr>
<tr>
<td>DP</td>
<td>Drillpipe</td>
<td></td>
</tr>
<tr>
<td>ECD</td>
<td>Equivalent Circulating Density</td>
<td>ppg</td>
</tr>
<tr>
<td>ESD</td>
<td>Equivalent Static Density</td>
<td>ppg</td>
</tr>
<tr>
<td>F</td>
<td>Force</td>
<td>lbf</td>
</tr>
<tr>
<td>FCP</td>
<td>Final Circulating Pressure</td>
<td>psi</td>
</tr>
<tr>
<td>ft</td>
<td>Feet</td>
<td>ft</td>
</tr>
<tr>
<td>Gm</td>
<td>Gas Migration Rate</td>
<td>ft/hr</td>
</tr>
<tr>
<td>h</td>
<td>Height</td>
<td>ft</td>
</tr>
<tr>
<td>Hm</td>
<td>Height of Migration</td>
<td>ft</td>
</tr>
<tr>
<td>HP</td>
<td>Hydrostatic Pressure</td>
<td>psi</td>
</tr>
<tr>
<td>hr</td>
<td>Hour(s)</td>
<td>hr</td>
</tr>
<tr>
<td>ICP</td>
<td>Initial Circulating Pressure</td>
<td>psi</td>
</tr>
<tr>
<td>ID</td>
<td>Internal Diameter</td>
<td>in</td>
</tr>
<tr>
<td>IDLH</td>
<td>Immediately Dangerous to Life and Health</td>
<td>in</td>
</tr>
<tr>
<td>in</td>
<td>Inch(es)</td>
<td>in</td>
</tr>
<tr>
<td>IPR</td>
<td>Inflow Performance Relationship</td>
<td></td>
</tr>
<tr>
<td>KMW</td>
<td>Kill Fluid Weight / Kill Mud Weight</td>
<td>ppg</td>
</tr>
<tr>
<td>L</td>
<td>Length</td>
<td>ft</td>
</tr>
<tr>
<td>lbf</td>
<td>Pound-Force</td>
<td>lbf</td>
</tr>
<tr>
<td>lbm</td>
<td>Pound-Mass</td>
<td>lbm</td>
</tr>
<tr>
<td>$L_F$</td>
<td>Length of Free Pipe</td>
<td>ft</td>
</tr>
<tr>
<td>LOT</td>
<td>Leak-off Test</td>
<td></td>
</tr>
<tr>
<td>M</td>
<td>Molar mass</td>
<td>lb/lb-mole</td>
</tr>
<tr>
<td>m</td>
<td>mass</td>
<td>lbs</td>
</tr>
<tr>
<td>MD</td>
<td>Measured Depth</td>
<td>Ft</td>
</tr>
<tr>
<td>MPD</td>
<td>Managed Pressure Drilling</td>
<td></td>
</tr>
<tr>
<td>Term</td>
<td>Description</td>
<td>Unit</td>
</tr>
<tr>
<td>-----------</td>
<td>-----------------------------------------------------</td>
<td>-----------------------------</td>
</tr>
<tr>
<td>MW</td>
<td>Fluid Weight / Mud Weight</td>
<td>ppg</td>
</tr>
<tr>
<td>n</td>
<td>Number of moles</td>
<td>mole</td>
</tr>
<tr>
<td>OBM</td>
<td>Oil Base Mud</td>
<td></td>
</tr>
<tr>
<td>OD</td>
<td>Outer Diameter</td>
<td>in</td>
</tr>
<tr>
<td>OMW</td>
<td>Original Fluid Weight / Original Mud Weight</td>
<td>ppg</td>
</tr>
<tr>
<td>OSHA</td>
<td>Occupational Health and Safety Administration</td>
<td></td>
</tr>
<tr>
<td>P</td>
<td>Pressure</td>
<td>psi</td>
</tr>
<tr>
<td>P_{DOI}</td>
<td>Pressure at Depth of Interest</td>
<td>psi</td>
</tr>
<tr>
<td>PI</td>
<td>Productivity Index</td>
<td></td>
</tr>
<tr>
<td>ppg</td>
<td>Pounds per Gallon</td>
<td>ppg</td>
</tr>
<tr>
<td>PPM</td>
<td>Parts per Million</td>
<td>PPM</td>
</tr>
<tr>
<td>psi</td>
<td>Pounds per Square Inch</td>
<td>psi</td>
</tr>
<tr>
<td>R</td>
<td>Universal Gas Constant</td>
<td>$ft^3 \times \text{psi} / ^\circ R \times (\text{lb} - \text{mole})$</td>
</tr>
<tr>
<td>R_{surf}</td>
<td>Surface Temperature</td>
<td>°F</td>
</tr>
<tr>
<td>TVD</td>
<td>True Vertical Depth</td>
<td>ft</td>
</tr>
<tr>
<td>Vol</td>
<td>Volume</td>
<td>bbl</td>
</tr>
<tr>
<td>V</td>
<td>Sacks of Barite per barrel of water</td>
<td>sacks/bbl</td>
</tr>
<tr>
<td>V_{DOI}</td>
<td>Volume at Depth of Investigation</td>
<td>bbl</td>
</tr>
<tr>
<td>v_e</td>
<td>Temperature Expansion Factor</td>
<td>ppg/100 °F</td>
</tr>
<tr>
<td>W</td>
<td>Weight</td>
<td>lbm</td>
</tr>
<tr>
<td>WBM</td>
<td>Water Base Mud</td>
<td></td>
</tr>
<tr>
<td>WG</td>
<td>Weight of gas</td>
<td>ppg</td>
</tr>
<tr>
<td>YP</td>
<td>Yield point</td>
<td>Lb/100ft²</td>
</tr>
<tr>
<td>ΔP</td>
<td>Change in Pressure</td>
<td>psi</td>
</tr>
<tr>
<td>Δt</td>
<td>Change in Time</td>
<td>hr</td>
</tr>
</tbody>
</table>

**Common Fluid Densities**

The table below displays the densities of common fluids used during well control operations.
Common Fluid Densities

<table>
<thead>
<tr>
<th>Fluid Type</th>
<th>Typical Density Range (ppg)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Fresh Water</td>
<td>8.33</td>
</tr>
<tr>
<td>Lease Water</td>
<td>8.4 – 10.0</td>
</tr>
<tr>
<td>Calcium Chloride (CaCl₂)</td>
<td>10.5 – 11.7</td>
</tr>
<tr>
<td>Calcium and Zinc Bromides (CaBr₂ and ZnBr₂)</td>
<td>15.0 – 19.2</td>
</tr>
<tr>
<td>2% Potassium Chloride Brine (2% KCl)</td>
<td>8.44</td>
</tr>
<tr>
<td>3% Potassium Chloride Brine (3% KCl)</td>
<td>8.49</td>
</tr>
<tr>
<td>Potassium Chloride Brines (KCl)</td>
<td>8.4 – 9.7</td>
</tr>
<tr>
<td>Sodium Chloride Brines (NaCl)</td>
<td>8.4 – 10.0</td>
</tr>
<tr>
<td>Diesel</td>
<td>7.0</td>
</tr>
<tr>
<td>Crude Oil (27° API)</td>
<td>7.45</td>
</tr>
<tr>
<td>Crude Oil (35° API)</td>
<td>7.0</td>
</tr>
<tr>
<td>Gasoline</td>
<td>6.0 – 7.3</td>
</tr>
<tr>
<td>Steel</td>
<td>65.5</td>
</tr>
<tr>
<td>Seawater (surface)</td>
<td>8.5 – 8.6</td>
</tr>
<tr>
<td>Seawater (deep ocean)</td>
<td>8.76</td>
</tr>
</tbody>
</table>

Gas Law Equations

\[
P = \frac{WG \times n \times R \times T}{m}
\]

OR

\[
P = \frac{WG \times R \times T}{M}
\]

Where

\[
P = \text{pressure of the gas, psi}
\]

\[
WG = \text{weight (density) of the gas, lb/gal}
\]

\[
n = \text{number of moles, lb-mole}
\]

\[
R = 10.73 \text{ ft}^3 \text{psi} \text{ lb-mole}
\]

\[
T = \text{temperature of the gas, Rankine, °R}
\]

Must convert Fahrenheit to Rankine

\[
1 \degree F = 460 \degree R
\]

\[
m = \text{mass of the gas, lbs}
\]

\[
M = \text{molar mass, lb/lb-mole}
\]

The molar mass of the gas is well documented. Common values for natural gas lie between the range of 16-20 lb/lb-mole.
General Pressure and Friction Loss Formulas

\[ P_2 = P_1 \times \left( \frac{SPM_2}{SPM_1} \right)^2 \]

\[ ECD = \frac{YP}{11.7 \times (ID_{hole} - OD_{pipe})} + MW \]

\[ \Delta P_{ann} = \frac{YP \times L}{225 \times (ID_{hole} - OD_{pipe})} \]

\[ ECD = \frac{\Delta P_{ann}}{0.052 \times TVD} + MW \]

Where

- \( P_1 \) = Original pressure, psi
- \( P_2 \) = New pressure, psi
- \( SPM_1 \) = Original pump rate, SPM
- \( SPM_2 \) = New pump rate, SPM
- \( ECD \) = Equivalent Circulating Density, ppg
- \( YP \) = Yield Point of fluid, lb/100 ft²
- \( MW \) = Fluid Weight, ppg
- \( ID_{hole} \) = Inner diameter of the wellbore, in
- \( OD_{pipe} \) = Outer diameter of the pipe, in
- \( \Delta P_{ann} \) = Friction pressure loss in the annulus, psi
- \( L \) = Length of annular section, ft
- \( TVD \) = True Vertical Depth, ft

Kick Causes and Detection

Kick Definition

A kick is an undesired influx of formation fluid into a wellbore.

Kicks can lead to catastrophic blowouts and other serious well control events.

Causes of Kicks

There are several causes of kicks in drilling and workover.

- Insufficient mud weight
- Improper hole fill while tripping
- Swabbing while pulling the drill string
- Loss of hydrostatic due to lost circulation
- Pressure communication from another well
- Large light weight spacers

These causes are mostly avoidable with good pre-planning and careful drilling practices.

Kick Detection

The primary indicators that a well is kicking are as follows:

- Increase in flow while circulating
- Flow with the pumps off
- Pit gain
- Improper hole fill while tripping
Secondary indicators of a kick can include the following:

- Drilling break
- String weight change
- Water or oil cut mud
- Decrease in pump pressure

Kick detection in oil or synthetic base mud can be masked to some degree if the kick fluid is soluble in the mud. Gas and oil kicks mix with the mud and therefore do not displace the mud in the well as efficiently as with water base fluids.

**Kicks in Oil or Synthetic Mud**

Gas and oil are soluble in synthetic and oil base mud. The amount of gas that can be solubilized depends on numerous factors such as pressure and temperature. As a result, the amount of gas entrained in these fluids at depth is more than when the gas and mud are at the surface.

When circulating gas saturated mud from depth, the gas will rapidly come out of solution when the mixture reaches its bubble point pressure. This fact has resulted in several serious blowouts and well control events.

The following are points to consider when using oil or synthetic base mud:

- Extended flow checks to allow sufficient gas to enter the wellbore and saturate the oil base mud at the kick zone.
- Controlled ROP in soft formations should be considered. This will help prevent gas from the cuttings from saturating the mud and "flashing out" when it reaches the bubble point.

**Kicks with MPD**

When using Managed Pressure Drilling (MPD) a Coriolis meter in the MPD equipment can be used to detect very small changes in flow from the well while circulating. This tool is the most sensitive kick detection tool in use at the present time and should be considered when small margins between the pore pressure and frac gradient are present.

**Shut In Procedures**

**Minimizing the Kick**

One of the most important philosophies in well control is minimizing the kick size. The following rules of thumb are related to kick size:

- Large kicks result in high surface and downhole pressure
- Large kicks result in high gas volumes when circulated out
- Large kicks are more difficult to remove without complications

Early kick detection and subsequent shutting the well in are critical factors in successful kill operations.

**Hard Shut In**

A hard shut in requires that the drilling choke or HCR is closed before shutting in the well.

A hard shut in offers the following advantages:

- The procedure is faster
- The kick size is smaller
- The shut in procedure is easier to remember

The main disadvantage of a hard shut in is that a more intense pressure wave is generated in the well when the BOP is closed.
This is referred to as a fluid hammer. There is some debate as to whether this pressure wave can be large enough to a formation fracture. There are many factors that must be considered for this to be the case.

Shutting the well in using the annular, rather than using the rams, results in a smaller pressure wave due to the longer annular closing time. Closing the annular while the HCR is closed is still considered a hard shut in.

**Soft Shut In**

A soft shut in requires a lengthier shut in sequence. The choke and choke manifold must be open before closing the BOP in the soft shut in method. Once the BOP is closed the choke is closed and only then is the well completely shut in.

A soft shut in offers the following advantages:

- The pressure wave generated in the well is minimized
- The SICP can be immediately read after closing the choke

The disadvantages of a soft shut in are as follows:

- Longer time to accomplish
- Larger kick
- Higher casing pressure

There have been many instances in the past where the choke was open and the well continued to flow but the rig crew thought the well was shut in. This is the main hazard for the soft shut in method.

**Diverting**

If the formation strength of the casing shoe is sufficiently weak that the well may broach if a kick is taken and the well is shut in, a diverter should be used. When a diverter is in use the well will never be shut in. The kick is directed through a large ID line(s) to a safe place overboard or away from the rig.

Diverters are designed shut that when the diverter (or annular) is closed the diverter line automatically opens. Overriding this function to pressure test the diverter is a presents a situation where a disastrous mistake can occur if the system is not returned to normal operations before drilling ahead.

**Hole and Pipe Volume Calculations**

The capacity factor for pipe or open hole can be calculated by the following formula.

\[
CF = \frac{ID_{pipe}^2}{1029.4}
\]

Where

- \(CF\) = Capacity factor, bbl/ft.
- \(ID\) = Internal diameter of pipe or open hole, in

A modification of this formula can be used to calculate the

\[
ACF = \frac{(ID_{hole}^2 - OD_{pipe}^2)}{1029.4}
\]

Where

- \(ACF\) = Annulus capacity factor, bbl/ft.
- \(ID_{hole}\) = Open hole or casing internal diameter, in
- \(ID_{pipe}\) = Pipe internal diameter, in
Filling the Hole

It is imperative to regulate the hydrostatic pressure in the well by controlling the fluid column during tripping operations. Whether tripping pipe into our out of the hole, the height of the fluid column will fluctuate, thus altering the hydrostatic pressure working against the surrounding formation.

When tripping pipe into the hole, fluid is displaced from the wellbore as the much higher density steel pipe replaces the space occupied by the fluid. Conversely, when pulling pipe out of the hole the fluid level drops as the steel volume is removed, thus to maintain hydrostatic pressure drilling fluid must be pumped in. Removing the pipe volume causes a hydrostatic reduction. Pressure values will be impacted whether the pipe is open ended or closed. Tripping open ended, or dry, pipe will force less fluid out as opposed to tripping closed, or wet, pipe. This is because an open ended pipe will only displace a volume equivalent to that of the steel pipe walls, whereas tripping a closed pipe will displace the volume of steel and the internal volume within the length of pipe.

Displacement and capacity values for drillpipe and casing are well known and can be found in published data tables or calculated using the following equations:

\[
\text{Open Ended Pipe Displacement} = \frac{OD^2 - ID^2}{1029.4}
\]

\[
\text{Closed Pipe} = \frac{OD^2}{1029.4}
\]

\[
ACF = \frac{(\text{Hole ID})^2 - (DP \ OD)^2}{1029.4}
\]

\[
DP \ CF = \frac{(DP \ ID)^2}{1029.4}
\]

Hydrostatic Pressure Drop per Foot When Pulling Dry Pipe

\[
\Delta P = 0.052 \times \text{Fluid Weight} \times \frac{DP \ Dis \ ACF + DP \ Cap}{ACF}
\]

Hydrostatic Pressure Drop per Foot When Pulling Wet Pipe

\[
\Delta P = 0.052 \times \text{Fluid Weight} \times \frac{DP \ CF + DP \ Dis \ ACF}{ACF}
\]

Where:

\(OD = \text{Outer diameter of pipe, in}\)

\(ID = \text{Internal diameter of pipe, in}\)

\(ACF = \text{Annulus capacity factor, bbl/ft}\)

\(DP \ Dis = \text{Drillpipe Displacement, bbl/ft}\)

\(DP \ CF = \text{Drillpipe Capacity Factor, bbl/ft}\)

\(\text{Fluid Weight} = \text{Density of current wellbore fluid, ppg}\)
Gas Cut Mud

Gas cut mud is a phenomenon that is common in drilling and workover operations. This is especially true for water based fluids.

There are several causes for gas cut mud.

- The hydrostatic pressure in the well is underbalance to the formation pressure. If the gas zone has high permeability, a kick is the usual result. However, if the formation has low permeability then gas cut mud could occur.
- If the formations drilled contain gas then gas from the cutting can result in gas cut mud.
- Buoyancy is likely the most common factor. Gas is lighter than water and will migrate in the earth until it reaches a trap (gas sand). When the bit penetrates the trap the gas migration resumes into the wellbore. The result is gas cut mud. This is also a cause of trip gas.

Due to Boyle’s Law the gas at the bottom of the hole is compressed and has very little effect on reducing the mud weight at that depth. Almost all of the reduction in mud weight occurs in the very top of the hole. Therefore gas cutting has little effect on the total hydrostatic pressure.

There are 2 equations that can be used to calculate the hydrostatic pressure decrease due to gas cut mud.

Lapeyrouse et al

\[ HP \text{ Decrease} = \frac{100 \times (MW_{\text{uncut}} - MW_{\text{cut}})}{MW_{\text{cut}}} \]

Strong Equation

\[ HP \text{ Decrease} = \left( 2.3 \times \left( \frac{MW_{\text{uncut}} - MW_{\text{cut}}}{MW_{\text{cut}}} \right) \times \log_{10} \left( \frac{BHP}{14.7} \right) \right) 14.7 \]

Where

\( HP \text{ Decrease} = \text{Decrease in hydrostatic pressure, psi} \)
\( MW_{\text{uncut}} = \text{Original fluid weight, ppg} \)
\( MW_{\text{cut}} = \text{Gas cut fluid weight, ppg} \)
\( BHP = \text{Bottom-hole pressure in, psi} \)

The following chart illustrates the hydrostatic reduction for a 12000’ TVD well.
Other formulas assume that there has been a kick (pit gain) associated with the gas cut mud. Calculations that depend on the drilling rate and formation gas saturation can also be made.

**Accumulator Sizing**

The accumulator is designed so that stored energy can be used to operate the BOP functions without external power or energy available. Further information concerning accumulator sizing can be located in API Specification 16D.

Closing units usually consist of the following components.

- The accumulator bottles
- Two charging pumps operated by fully independent sources
- Control valves for the various functions (4-way valves)
- An hydraulic fluid reservoir
- A high pressure bypass
- An independently regulated segment for the control of the annular function
- A regulated manifold for the ram and valve functions
- A remote operating panel

**Accumulator Sizing for a Surface BOP Stack**

In order to properly close the BOP functions, an accumulator must be properly sized. Accumulator bottles consist of a bladder that holds a compressible gas (nitrogen) and isolates it from the control fluid. The bladder in the bottle is pre-charged to a specified pressure (1,000 - 1,100 psi). When pressure is applied
to the accumulator, the gas in the bottles is further compressed. This results in stored hydraulic energy that is available to operate the BOP functions.

The amount of the stored energy is governed by Boyle's law which is the underlying principle of the following accumulator sizing equation. This assumes that the gas in the bladder acts as an Ideal Gas.

The usable fluid per bottle is determined and then the number of bottles required can be calculated based on the specifications of the BOP stack in use.

**General Comments**

- Most surface BOP stacks accumulators operate on a system with 3000 psi hydraulic pressure and 1000 psi accumulator bottle pre-charge.
- It is generally recommended to size an accumulator such that the operating pressure is 200 psi over the pre-charge pressure when all BOP components have been functioned with the charge pump systems isolated.
- The accumulator should have a light or audible alarm that sounds when the accumulator pumps are running.
- The remote panel should be tested weekly at a minimum.
- If the accumulator pumps repeatedly run when the BOP has not been functioned, investigate this issue. There is likely a leak in the system. Accumulator 4-way valves should be placed in the actuated position (open or closed), not in the neutral position during normal drilling operations.

![Internal diagram of accumulator bottle at precharge pressure, minimum pressure and working pressure.](image-url)
Accumulator Sizing Formulas

To Determine Number of Nitrogen Bottles

Control Fluid Volume = Sum of all closing volumes

The accumulator bank control fluid volume is the total volume needed to close all preventers and HCR valves

Usable Fluid Volume with 50% Reserve Factor = 150% × Control Fluid Volume

API recommends a reserve factor of 50%.

Minimum Pressure = \( \frac{BOP \text{ Pressure rating}}{\text{Ram Closing Ratio}} \)

Total Accumulator Bank Volume = \( \frac{Usable \text{ Fluid Volume}}{\frac{\text{Precharge Pressure}}{\text{Minimum Pressure}} - \frac{\text{Precharge Pressure}}{\text{Working Pressure}}} \)
Number of bottles required = \(\frac{\text{Total Accumulator Bank Volume}}{\text{Volume of 1 Bottle}}\)

**Accumulator Bottle Volumes**

*Single Bottle Working Volume at Precharge Pressure*
\[= \text{Accumulator Bottle Volume} - \frac{\text{Precharge Pressure} \times \text{Accumulator Bottle Volume}}{\text{Working Pressure}}\]

*Single Bottle Nitrogen Volume at Precharge Pressure*
\[= \frac{\text{Precharge Pressure} \times \text{Accumulator Bottle Volume}}{\text{Working Pressure}}\]

*Bottles to Close All = \frac{\text{Control Fluid Volume}}{\text{Single Bottle Working Volume}}*

*Bottles to Open All = \frac{\text{Sum of all Opening Volumes}}{\text{Single Volume Working Volume}}*
Total Working Volume = Single Bottle Working Volume \times Total Bottles

Total Nitrogen Volume = Single Bottle Nitrogen Volume \times Total Bottles

Pressure after shutting each BOP component = \frac{Precharge Pressure \times Accumulator Bottle Volume \times Total Bottles}{Total Nitrogen Volume + Component Closing Volume}

Total Volume Drop = Total Working Volume − Component Closing Volumes

Volume Drop Per Bottle = \frac{Component Closing Volume}{Total Bottles}

Usable Fluid Volume = \left( \frac{Working Pressure \times Precharge Pressure \times Bottle Volume}{Minimum Pressure \times Working Pressure} \right) − \frac{Precharge Pressure \times Bottle Volume}{Working Pressure}
Mud Gas Separator Sizing
The Mud Gas Separator (MGS) is used to remove free gas from the drilling fluids. The sizing of the MGS depends on several components and how the system is installed. Take care when referencing any “maximum” performance metrics, as these are based on various assumptions they may not be relevant to all scenarios.

There are two primary sizing components for the MGS:

- The ID of the vessel
- The “working” pressure of the vessel

The ID of the MGS impacts the retention time of the fluids for separation. Insufficient time in the MGS can lead to gas-cut fluids at the shakers. The retention time is also dependent on the circulation rate of fluids into the MGS. Slower circulation rates provide longer retention time in a vessel of the same size, and therefore improve MGS performance.

The working pressure of the MGS changes with the height of the mud leg and the density of fluid in the mud leg. The hydrostatic pressure of the fluid in the mud leg gives the maximum pressure that can be present in the MGS chamber without the blow-through of gas/drilling fluids to the shakers or pits. This establishes the fluid seal between the MGS and the pit system. The internal pressure in the vessel is equal to the frictional pressure of the gas flow exiting the MGS through the vent line. Several factors can influence the frictional pressure in the vent line and these are as follows:

- The “effective” length of the vent line
  - “Effective” length is the actual measured length, plus an additional length that correlates to any bends in the pipe
  - The severity of the bend impacts the additional length to be added.
- The flow rate of gas through the vent line
- The ID of the vent line
- Any flow impediment devices in the vent line
  - Ignition systems
  - Back flow devices

The fluid seal would be lost if the working pressure in the MGS exceeds the hydrostatic pressure of the mud leg. This condition can present a significant safety hazard and should be avoided. Should this occur, the following steps are advised:

- Stop circulation and shut-in the well
- Fill the MGS with fluid and prepare to restart the circulation process
- Lower the circulation rate
  - Increase fluid retention time in the MGS
  - Decrease the peak gas rates and resultant frictional pressure in the vent line

There is several different means to calculate the various aspects of MGS sizing. In many cases, the installation cannot be modified without significant effort, and the maximum values for the system are desired. The following formulas have some simplified assumptions to provide an estimate on what the MGS system can handle.

Working Pressure for MGS:

\[ WP = 0.052 \times MW \times H_{ml} \]
Where

\( WP = \) Working Pressure, psi
\( H_{ml} = \) Height of mud leg, ft
\( MW = \) Mud Weight of Fluid in the MGS, ppg

The Weymouth Equation can be used to calculate the maximum gas rate allowed through a MGS system, given a working pressure. This equation has been simplified with some basic assumptions and is as follows:

\[
Q_g = 1.1 \times ID^{2.67} \left[ \frac{0.002876 \times WP \times (WP + 29.4)}{L_E} \right]^{1/2}
\]

Where

\( Q_g = \) Maximum Gas Rate for System, MMscf/d
\( ID = \) Internal Diameter of the Vent Line, in
\( WP = \) Working Pressure, psi
\( L_E = \) Effective Length of Vent Line, ft

Assumptions associated with the above formula:
- \( SG = 0.65 \)
- Temperature = 75°F
- Pressure at the end of the vent line is atmospheric (14.7 psi)

A maximum circulation rate into the MGS can be determined based on the vessel ID and some assumptions. A conservative value for the migration rate of gas through a Water-Based Mud (WBM) system is given by MacDougall 500 ft/hr or 8.4 ft/min. MacDougall also suggested that the return rate from the well during a kick circulation for various kick sizes and pressures was approximately twice that of the circulation rate. These are the metrics used in the following equations for maximum circulation rate. This ONLY evaluates retention time of fluids in the vessel. The MGS may be further limited by the previous calculated maximum gas rates and warrant a reduced circulation rate than what is determined with the following equations.

\[
CF_{MGS} = \frac{ID^2}{1029.4}
\]

\[
Q_{MGS} = CF_{MGS} \times 8.4
\]

\[
Max \, Circulation \, Rate = \frac{Q_{MGS}}{2}
\]
A leak-off test (LOT) is used to verify that the formation just below the casing shoe can withstand the wellbore pressure required to drill onto the next casing setting depth. A LOT can also verify that the cement is providing the proper isolation from weaker zones behind the last casing string. When new formation is exposed after drilling out the casing shoe, drilling fluid of a constant density is slowly pumped into the wellbore while annular pressure and volume pumped is monitored and plotted on a chart similar to the figure below. The wellbore pressure will increase at a constant rate per volume unit while drilling fluid is being pumped in prior to any fracturing of the formation. This should be a linear trend on the plot. At the first sign of a deviation from this linear trend, the formation integrity has been breached and drilling fluid has begun to leak off (fracture initiation) into the surrounding formation. The pressure value at this point can be called the leak-off pressure. It is important to remember that the leak-off pressure is not where the pressure peaks, it is where the deviation from the linear trend occurs. In the graph below this point is illustrated to be within the red circle.

**Information Gained from LOT**

- Leak-off pressure is the pressure at which the formation will begin to fracture.
- Leak-off pressure results dictate maximum drilling fluid density and wellbore pressure to be used during operations
- Substantially lower values can indicate that cement isolation from weaker shallow zones has not been
established. This may indicate the need to "squeeze" the shoe.

**Procedure**

1. Once new formation is drilled, circulate wellbore to ensure uniform drilling fluid density throughout.
2. Prepare a chart to plot annular pressure against volume of drilling fluid pumped, set up similar to the figure below.
3. Close the BOP and slowly pump drilling fluid into the wellbore with constant strokes, noting annular pressure, drillpipe pressure, volume of fluid pumped and stroke count.
4. Drillpipe pressure and annular pressure will increase as more drilling fluid is pumped into the wellbore.
5. Carefully monitor annular pressure and volume pumped. The red circled area in the figure denotes the leak-off pressure. This occurs when values deviate from the linear trend. Stop pumping drilling fluid.
6. Observe pressure for a period of 10 minutes to ensure pressure stabilization.

**Casing Integrity Test**

A casing integrity test should be conducted to evaluate the integrity of the cased wellbore prior to drilling out the shoe track. Test pressure values should be specified in the drilling program and based on maximum anticipated pressures for each casing.
size. Many companies have specific casing test criteria that must be followed.
The following parameters should be accounted for in the design of a casing integrity test:

- Pertinent regulatory requirements
- Frictional pressure losses
- Fluid compressibility
- Thermal effects on the fluid system
- Failure point of the weakest casing in the string
- Fluid density and distribution within the wellbore
- Minimum design factor assumed in casing design
- Pressure effects on tensile loads
- Liner overlaps

When conducting a casing integrity test, consideration should be made regarding the following:

- BOP selection and space out
- Choke and valve alignment
- Confirm a full and static fluid column with consistent density throughout the wellbore
- BOP closing procedures from the rig contractor
- Choke line and pump line integrity/limitations
- Method for volume/pressure monitoring (i.e. allocated shut in time, shut in behavior observation)
- Test data interpretation
- Pressure vs. volume chart
  - Pressure vs. time
  - Pumped volume vs. flow back volumes

**Kick Tolerance**

Kick tolerance is intended to describe the ability of a wellbore to withstand a kick without failure (generally assumed at the casing shoe), and allow the kick to be circulated out. There are 2 parameters that are involved in kick tolerance and both are dependent on the other. These are as follows:

2. Kick Intensity – difference in pressure between the reservoir and the wellbore.

Each parameter will impact the other directly. For example, as the volume of a kick taken increases, the allowable kick intensity is decreased. Same is true for the kick intensity with respect to kick volume.

Kick tolerance also depends directly on the fracture pressure of the weakest exposed formation, normally assumed to be the last casing shoe. This will dictate the maximum pressure that can be generated in the wellbore at the zone at any given point during drilling/well control operations.

Static kick tolerance calculations can be completed with some basic equations. These calculations can be inadequate in many situations and do not make an assessment of the ability to actually circulate out the kick. Well control software can be used to determine a "dynamic" kick tolerance and can account for wellbore and reservoir fluid interactions, which are also not included in the static calculations.
Some basic calculations of general interest are:

1. Maximum allowable surface pressure with a given mud weight.
2. Maximum kick intensity allowable at ZERO volume of influx.

**Basic Static Calculations:**

\[
MAASP = P_{Frac} - (0.052 \times \text{MW} \times TVD_{Shoe})
\]

\[SICP > MAASP \rightarrow \text{Fracture at Shoe}\]

\[K_{I\text{max}} = \frac{MAASP}{TVD_{Res} \times 0.052}\]

*Where*

- \(MAASP\) = Maximum Allowable Annular Surface Pressure, psi
- \(P_{Frac}\) = fracture pressure at the casing shoe, psi
- \(K_{I\text{max}}\) = Maximum Kick Intensity at ZERO volume influx, ppg

**Assumptions:**

- Accounts for no hydrostatic pressure of the kick fluids.
- Incompressible wellbore fluids.
- No temperature and pressure effects on the well fluids.
- Does not account for friction or circulation of fluids.
- MAASP assumes drilling fluid to the casing shoe from the surface, i.e. no kick fluids above the shoe.

**Oil-Based Mud Corrections**

Oil-Based Mud (OBM) density can be influenced by pressure and temperature throughout the wellbore. Therefore, it is often desired to apply correction calculations to estimate the actual downhole density of the fluid. Correction equations and factors below come directly from *API Recommended Practice 13D*.

A chart is included below with temperature and pressure coefficients for common base fluids and 19.35 by weight Calcium Chloride (CaCl\(_2\)) water.

*API Recommended Practice 13D* suggests that the wellbore be broken into "sections" for the calculation of the Equivalent Static Density (ESD) over the length of the section. The calculated pressure value from the previous section is used for the following section in an iterative manner to the well total depth. This type of calculation procedure is generally best accomplished by use of a spreadsheet.

**Temperature and Pressure Coefficients**

<table>
<thead>
<tr>
<th>Fluid</th>
<th>9.3% by wtCaCl(_2)</th>
<th>Diesel</th>
<th>Mineral Oil</th>
<th>Internal Olefin</th>
<th>Paraffin</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Pressure Coefficients</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>(a_i) (ppg)</td>
<td>9.99</td>
<td>7.32</td>
<td>6.99</td>
<td>6.84</td>
<td>6.97</td>
</tr>
<tr>
<td>(b_i) (ppg/psi)</td>
<td>1.77E-05</td>
<td>5.27E-05</td>
<td>2.25E-05</td>
<td>2.23E-05</td>
<td>3.35E-05</td>
</tr>
<tr>
<td>(c_i) (ppg/psi(^2))</td>
<td>6.0E-11</td>
<td>-8.0E-10</td>
<td>-1.0E-10</td>
<td>-2.0E-10</td>
<td>-5.0E-10</td>
</tr>
</tbody>
</table>

| **Temperature Coefficients** |                      |        |             |                 |          |
| \(a_i\) (ppg/F)  | -2.75E-03              | -3.15E-03 | -3.28E-03  | -3.39E-03       | -3.46E-03 |
| \(b_i\) (ppg/psi/F) | 3.49E-08               | 7.46E-08  | 1.12E-07  | 1.12E-07        | -1.64E-08 |
| \(c_i\) (ppg/psi\(^2\)/F) | -9.0E-13              | -1.0E-12  | -3.0E-12  | -2.0E-12        | 2.0E-13  |

All pressure units are psi

All Temperature units are degrees Fahrenheit

These values are valid for normal ambient temperatures up to approximately 400°F and pressure up to at least 14,500 psi.
From a retort analysis, the density of the mud solids and the volumes of the individual components can be determined:

\[ Vol_{\text{Total}} = Vol_{\text{base}} + Vol_{\text{brine}} + Vol_{\text{solids}} = 1 \]

\[ Vol_{\text{brine}} = Vol_{\text{water}} + Vol_{\text{salt}} \]

Salt content approximation for 19.3% by weight CaCl$_2$ is:

\[ Vol_{\text{salt}} = 0.056704 \]

Corrected volume for Drilled Solids is:

\[ Vol_{DS} = Vol_{\text{solids}} - \left( \frac{0.056704 \times Vol_{\text{water}}}{100} \right) \]

Use the components in the table above to complete the following corrections for the mud weight (density) for the brine and base fluid:

\[ MW_{\text{base}} = (a_1 + b_1 \times P + c_1 \times P^2) + (a_2 + b_2 \times P + c_2 \times P^2) \times T \]

\[ MW_{\text{brine}} = (a_1 + b_1 \times P + c_1 \times P^2) + (a_2 + b_2 \times P + c_2 \times P^2) \times T \]

The final density for each section can be calculated from the following:

\[ MW_{\text{section}} = \left( \frac{Vol_{\text{base}}MW_{\text{base}} + Vol_{\text{brine}}MW_{\text{brine}} + Vol_{DS}MW_{DS}}{Vol_{\text{Total}}} \right) \]

The ESD at the end of each section, and for the entire well can be then calculated using the determined corrected mud weights.

**Ballooning**

The term “ballooning” generally refers to the flow back of fluids previously lost into a formation. The pressure associated with ballooning is typically a function of the fracture initiation and fracture closure pressures of the rock. There is also generally a finite volume of fluids for the ballooning system. As a volume of fluids are taken back into the well from the formation, the associated pressure is reduced.

Ballooning generally occurs while circulating when the Equivalent Circulating Density (ECD) is higher than the pressure required to open a fracture in the ballooning formation. When circulation is stopped and the Equivalent Static Density (ESD) at the formation is less than the fracture closure pressure lost fluids will reenter the wellbore, giving the perception of a kick.

Fingerprinting can also be used to assisting the determination of a well that is kicking as opposed to ballooning. The flowback of fluids upon each connection should show a decreasing flow rate trend and should match those of previous connections.

Pressure build fingerprinting can also be completed to show a reduction in the pressure related to time when compared to a consistent volume of fluid bled back. The following chart shows an example of a ballooning well. Three bleed cycles were
complete and the pressure build was plotted over time for comparison. The decreasing trend can be noted which was instrumental in the conclusion that ballooning was the source of flow realized from the well.

This event can be mistaken for a kick, or a kick can be misinterpreted as ballooning. The investigation of ballooning should occur in a control manner

Always treat any well flow as a kick until it can be proven otherwise. Never assume that the well is ballooning.

Some general concepts to remember about ballooning:

- Fluid lost to the ballooning formation is required to induce ballooning.
- The shut-in pressure should not increase after a volume of fluid is bled off. A pressure increase is the sign of a kick and NOT ballooning.
- Fluid return rate should not increase. A decreasing trend is expected as the volume in the ballooning formation is reduced.
- Shut-in pressure will not increase due to fluid/gas migration in the well in a pure ballooning scenario.
- Ballooning is normally associated with shales, or other low permeability zones.
Ballooning formations are generally close to the last casing shoe depth as fracture pressures typically increase with increasing depth.

It is important to remember that any diagnostic work, consistency is the key. In order to compare data points for a bleed off of fluids, the process must be consistent. This should be considered when attempting to verify if ballooning has occurred or if the resulting pressure and volume are the result of a kick.

The following is a simple generalized procedure to assist with the identification of ballooning:

- Record the initial stabilized SICP.
- Bleed off a small, measured volume into the trip tank (or another calibrated tank for reading small volumes).
  - A suggestion would be 5 bbl or less.
- With the choke left at the same opening size, time the flow back for each barrel.
  - A trend that shows a flow rate reduction is a sign of ballooning.
- Shut-in the well and record and plot the resulting casing pressure until it has stabilized.
  - If the pressure is lower than the original SICP, continue to bleed off small volume increments.
  - Once it can be established that the source of flow is ballooning, continue operations as required.

**Kick Removal: Driller’s Method**

The goal of the Driller’s Method is to kill the well in 2 circulations while maintaining constant bottom-hole pressure (BHP). The 1st circulation displaces the kick with existing wellbore fluid, while the 2nd circulation kills the well by displacing the well with a heavier kill weight fluid. If the kick was swabbed in and the original fluid weight was sufficient to overbalance the formation, the well can be killed on the 1st circulation with no fluid weight increase required.

**Procedure**

1. Shut the well in.
2. Record stabilized casing and drillpipe pressures. Note pit level.
3. Perform all necessary calculations with equations provided.
4. Hold casing pressure constant and bring pump to desired rate.
5. Holding drillpipe pressure constant, complete one full circulation of the entire wellbore volume.
6. Once the kick is safely removed, shut the well in and verify casing and drillpipe pressures are equal.
   a. If they are NOT equal, this could indicate that the kick has not been fully removed, or a secondary kick has occurred.
7. Calculate kill fluid weight and raise mud weight for the 2nd circulation.
8. Calculate the strokes to displace the kill fluid to the bit.
9. Holding casing pressure constant, bring pumps to speed.
10. Upon reaching the kill rate, note the Initial Circulating Pressure (ICP) on the drillpipe. This will be the value to use for ICP on the pump schedule.
11. NOTE: Should ICP value on drillpipe gauge differ from calculations within a reasonable amount, use gauge value and adjust pump schedule accordingly.
12. Follow pump schedule for the drillpipe pressure making the necessary adjustments to reduce the drillpipe pressure as needed.
13. When kill weight fluid reaches the bit, this is the value for Final Circulating Pressure (FCP).
14. Hold drillpipe pressure constant at FCP and continue to circulate kill fluid to the surface.
15. Once kick is safely removed, shut well in and verify casing and drillpipe pressure equal 0 psi. Any trapped pressure in the wellbore system may need to be bled off.

Procedural Notes

1st Circulation: Removes the kick (influx) with existing wellbore fluid (current drilling fluid in the hole and the pits). Kick is to be fully circulated out. While bringing pumps online, keep casing pressure constant until desired rate is reached. After reaching the kill rate, hold the drillpipe pressure constant until the kick is safely removed to maintain a constant BHP. Once kick has been circulated out, casing and drillpipe pressure should be equal. If they differ, this signifies that a fluid imbalance may be present in the wellbore. This should be further investigated.

NOTE: Expansion will occur as gaseous kick is circulated up wellbore. Pit gain and casing pressure should increase until kick is removed. For this reason, the pit volume should not be used as a primary parameter to manage the kick circulation.

2nd Circulation: Existing fluid is replaced with kill fluid. Calculate kill mud weight using the drillpipe pressure. While bringing pumps online, keep the casing pressure constant until desired rate is reached. Once the desired rate is reached, this value is the ICP. Follow the pumping schedule while kill weight fluid is pumped to the bit. Hold drillpipe pressure constant at FCP while kill weight fluid is circulated from the bit to surface. Shut the well in and confirm that casing and drillpipe pressure are equal at 0 psi. Bleed off any trapped pressure in small, controlled increments.

Advantages
- Preferred during:
  - Water based kicks (time sensitive nature of gas migration).
  - Swabbed in kicks (no need for mud density increase).
- Simplicity.
- 1st Circulation can begin with minimal calculations.
- Well can be controlled (influx removed), not necessarily killed, if weighting material is unavailable.

Disadvantages
- Maximum pressure at casing shoe may be higher.
- Must confirm shoe fracture pressure and formation fracture pressure.

Equations

\[ KMW = \frac{SIDPP}{0.052 \times TVD} + OMW \]
\[ ICP = SIDPP + SPR \]
\[ FCP = \frac{KMW \times SPR}{OMW} \]
\[ Strokes \ to \ Bit = \frac{Drillstring \ Volume}{Pump \ Output} \]
\[ \text{Pump Time to Bit} = \frac{\text{Strokes to Bit}}{\text{Strokes per Bit}} \]

\[ ECD = \frac{\text{Annular Pump Pressure}}{0.052 \times \text{TVD}} \times \text{KMW} \]

\[ \text{CircPressure} = \text{SPR} + \text{DP Pressure} \]

Where

\( \text{KMW} = \text{Kill Mud Weight, ppg} \)
\( \text{SIDPP} = \text{Shut In Drilpipe Pressure, psi} \)
\( \text{TVD} = \text{True Vertical Depth, ft} \)
\( \text{OMW} = \text{Original Mud Weight, ppg} \)
\( \text{ICP} = \text{Initial Circulating Pressure, psi} \)
\( \text{FCP} = \text{Final Circulating Pressure, psi} \)
\( \text{SPR} = \text{Slow Pump Rate Pressure, psi} \)
\( \text{ECD} = \text{Equivalent Circulating Density, ppg} \)
\( \text{CircPressure} = \text{Circulating Pressure, psi} \)

**Kick Removal: Engineer’s Method**

Also known as Wait and Weight or the Balanced Method, the Engineer’s Method can be used to kill a well in one circulation when circulating on bottom. Kill fluid is pumped into the well in order to circulate out a kick (influx) and exert the needed hydrostatic pressure to overbalance the formation. Bottom-hole pressure (BHP) should remain constant throughout the procedure.

**Procedure**

1. Shut the well in.
2. Record stabilized casing and drillpipe pressures. Note pit level.
3. Perform all necessary calculations with the equations provided
4. Develop a pumping schedule.
5. Increase the mud weight to the calculated kill mud weight.
6. Hold casing pressure constant while bringing the pump(s) to kill rate.
7. Upon reaching the kill rate, note the Initial Circulating Pressure (ICP) on the drillpipe. This will be the value to use for ICP on the pump schedule.
   a. NOTE: Should ICP value on drillpipe gauge differ from calculations within a reasonable amount, **use gauge value** and adjust pump schedule accordingly.
8. Follow pump schedule for the drillpipe pressure making the necessary adjustments to reduce the drillpipe pressure as needed.
9. When kill weight fluid reaches the bit, this is the value for Final Circulating Pressure (FCP).
10. Hold drillpipe pressure constant at FCP and continue to circulate kill fluid to the surface.
11. Once the kick is safely removed, shut the well in and verify casing and drillpipe pressure equal 0 psi. Any trapped pressure in the wellbore system may need to be bled off.

**Procedural Notes**

Removes the kick (influx) with weighted up kill fluid in a single circulation. While bringing pumps online, keep the casing pressure constant until desired rate is reached. Once the desired rate is reached, this value is the ICP. Follow the pumping
schedule while kill weight fluid is pumped to the bit. Hold drillpipe pressure constant at FCP while kill weight fluid is circulated from the bit to surface.

**Advantages**
- Theoretically kills the well with a single circulation.
- Generally lower overall wellbore pressures.
  - Lower expected pressure at the shoe.
- The pressure throughout the entire wellbore should be reduced as compared to the Driller's method.

**Disadvantages**
- Requires materials on hand to weight up the fluid.
- Fluid weight up is not required on all kick scenarios.
- Time is required to weight up mud.
  - Gas migration is a time sensitive issue in a water-based mud system.

**Equations**

\[
KMW = \frac{SIDPP}{0.052 \times TVD} + OMW
\]

\[
ICP = SIDPP + KRPP
\]

\[
FCP = \frac{KMW \times KRPP}{OMW}
\]

\[
\text{Strokes to Bit} = \frac{Drillstring\ Volume}{\text{Pump Output}}
\]

\[
\text{Pump Time to Bit} = \frac{\text{Strokes to Bit}}{\text{Strokes per minute}}
\]

\[
ECD = \frac{\text{Annular Pump Pressure} \times KMW}{0.052 \times TVD}
\]

\[
\text{CircPressure} = KRPP + DP\ Pressure
\]

**Where**

- \(KMW = \text{Kill Fluid Weight, ppg}\)
- \(SIDPP = \text{Shut In Drillpipe Pressure, psi}\)
- \(TVD = \text{True Vertical Depth, ft}\)
- \(OMW = \text{Original Mud Weight, ppg}\)
- \(ICP = \text{Initial Circulating Pressure, psi}\)
- \(FCP = \text{Final Circulating Pressure, psi}\)
- \(SPR = \text{Slow Pump Rate Pressure, psi}\)
- \(ECD = \text{Equivalent Circulating Density, ppg}\)
- \(\text{CircPressure} = \text{Circulating Pressure, psi}\)

**Kick Removal: Lube and Bleed**

Lube and bleed is a method used to remove gas from a wellbore, while managing the BHP so that is does not drop below the initial starting value. This is accomplished by pumping a liquid into the well's void space (area at the surface occupied by the gas) and bleeding off a specific amount of pressure from the well by releasing GAS ONLY.

**Important Concepts to Remember**
- Only bleed gas
- Gas must be present at the surface to lube and bleed (or there is no void space to insert fluid into the well)
• Hydrostatic pressure added and the pressure increase from pumping (compression of the gas bubble) must be bled off after each pump cycle
• Set the pressure boundaries suitable to the wellbore limitations (casing shoe, surface pressure limits, etc.)

General Procedure
1. Set pressure/volume limits for pumping cycle.
2. Confirm that gas is present at the surface.
   a. Note the initial SICP
3. Pump the desired volume of lubricating fluid into the wellbore.
4. Allow for the liquid lubricating fluid to swap with the gas in the well.
5. Bleed the pressure on the casing back to the initial SICP at the beginning of the pump cycle.
6. Bleed off an additional pressure increment that is equivalent to the hydrostatic pressure added to the well by the pumped lubrication fluid.
7. Repeat until gas is removed. When all gas has been removed, lube and bleed is finished. The well may/may not be dead at this point.

Formulas
The added hydrostatic pressure is calculated as follows:
Calculate the height (pipe only or annulus) of the lubricating fluid column based on the pumped volume:

\[ h_{\text{pipe}} = \frac{V_{\text{lub}} \times 1029.4}{ID_{\text{pipe}}^2} \]
\[ h_{\text{Ann}} = \frac{V_{\text{lub}} \times 1029.4}{(ID_{\text{CSG}}^2 - OD_{\text{pipe}}^2)} \]

Hydrostatic pressure increase:

\[ P_{\text{hyd}} = 0.052 \times h \times MW \]

The gas bubble size can be calculated using Boyle's Law (see Boyle's Law Section for specific details):

Where

\[ H_{\text{Ann}} = \text{height of the lubricated fluid in an annulus, ft} \]
\[ h_{\text{pipe}} = \text{height of the lubricated fluid in pipe, ft} \]
\[ V_{\text{lub}} = \text{volume of lubricated fluid per cycle, bbl} \]
\[ P_{\text{hyd}} = \text{hydrostatic pressure increase from lubricating fluid, psi} \]
\[ MW = \text{lubricating fluid weight, ppg} \]

Kick Removal: Volumetric Method
The volumetric well control method is to be used when normal circulation is compromised. While regulating the bottom-hole pressure, the kick is allowed to migrate to the surface by bleeding calculated volumes of mud out. Once gas has reached the surface, the volumetric procedure is completed. Removal of the gas can be completed by lube and bleed, or other well control methods.
Below are some examples of when the volumetric method should be used (volumetric control is generally only needed if circulation is not possible):

- Casing pressure increase due to gas migration would reach unacceptable point before circulation could begin
- Off bottom but gas kick is below the bit (circulation would not remove the kick)
- Pumps are unable to be used
- Plugged drill string or bit and cannot circulate
- The well is shut in on the blind rams and there is no means of circulation.

**Procedure**

1. Record initial SICP.
2. Select a safety factor and working margin. Margins should be selected based on the well limitations. The working margin may also be known as the pressure increment.
3. Calculate the mud increment. The mud increment is the mud volume to be bled off, reducing the hydrostatic pressure in the well by the amount of pressure increase from the working margin. It can be determined using the following equation:
   \[
   \text{Mud Increment} = \frac{\text{Working Margin} \times ACF}{0.052 \times \text{Mud Weight}}
   \]
4. Allow casing pressure to rise by predetermined safety factor. This will allow the BHP to increase by the safety factor and will provide extra overbalance. This pressure will NOT be bleed off.
5. Allow casing pressure to rise further by predetermined working margin. The BHP will increase by the working margin amount.
6. Accurately bleed off mud increment into a measuring tank (like the trip tank) while maintaining a constant casing pressure. This should decrease the hydrostatic pressure in the well by the working margin amount, reducing the BHP back to the original value prior to the increase from the working margin.
7. Repeat step 5 and 6 while recording casing pressure, calculating bottom-hole pressure, and tracking mud volumes bled off.
8. Stop the bleeding process when gas enters the choke. Kick is now to surface.
9. Proceed with additional operations to remove kick and kill the well.

**Trapped Pressure**

Pressure on a well after kill operations can be the result of trapped pressure induced during the kill circulation. There have been a multitude of well control jobs that were the result of bleeding the well and assuming that pressure on the well was trapped pressure when it was actually the result of a kick.

Checking for trapped pressure can be safely accomplished without allowing an additional kick into the well if done properly.

**Bleed Outline**

The following outline can be used to bleed trapped pressure. Modification of this outline can be made to bleed a small volume
of fluid in the well instead of a small pressure as is in this procedure.

- Record the pressure. This is the starting pressure.
- Ensure that the pressure is stable for at least 30 minutes.
- Pick a small pressure increment to bleed (50-150 psi).
- Line up the choke manifold to the trip tank so that the volume bled can be accurately measured.
- Bleed the small pressure increment (50-150 psi) slowly and close the choke.
- Observe and record the pressure.
- Allow the pressure to stabilize.
- If the pressure returns to or rebounds above the starting pressure stop the bleed process. This indicates the well is likely balanced to the reservoir pressure.
- If the pressure after bleeding does not return to the starting pressure, consider an additional bleed cycle.

The main point to remember is that the pressure after bleeding should be less than the starting pressure. If the pressure after any bleed cycle rebounds to or above the starting pressure, the well is likely balanced to the reservoir pressure. Additional bleeding at this point will cause the well to be underbalanced and the well will kick during the bleed cycle.

If an additional kick is taken while attempting to bleed trapped pressure it will have to be removed by a kill circulation or expanded to the surface by volumetric control before the well can be checked for trapped pressure again.

**Best Practices**

Here are a few tips to consider when bleeding trapped pressure.

- Bleeding trapped pressure should be done through a choke. Never bleed trapped pressure through a gate valve. A lo-torq valve should also be avoided when bleeding trapped pressure back to a cement unit if possible.
- If gas is present during the bleed cycles, lube and bleed procedures should be followed to replace the gas pressure with fluid hydrostatic.
- Always measure the bleed volume. Bleeding the well through the mud-gas separator can lead to measurement errors if the separator is not full. Bleed the well to a trip tank.
- Ensure that the gauge in use for the bleed operation is in good working order. Try to use the same gauge for all bleed cycles as using multiple gauges can lead to confusion.

**Boyle’s Law**

Boyle’s Law stems from the ideal gas law at constant temperature and is simplified to the following equation in order to compare a gas bubble at different points of interest:

\[ P_1 V_1 = P_2 V_2 \]

Where

- \( P_1 \) = Pressure at condition 1
- \( V_1 \) = Volume at condition 1
- \( P_2 \) = Pressure at condition 2
- \( V_2 \) = Volume at condition 2
Concepts to remember:
- Does not account for temperature change
- Does not account for compressibility of gas

\( P_1V_1 = P_2V_2 \) can be rearranged into a ratio to solve for an unknown property.

**Example: What will the volume of a 10 bbl kick be at the surface?**

![Diagram](image)

Location 1:
Kick Detected
\( P_1 = 2700 \)
\( V_1 = 10 \)

Location 2:
Bubble migration and expansion
\( P_2 = 300 \)
\( V_2 = ? \)

\[ \frac{P_1V_1}{P_2} = V_2 \]
\[ \frac{(2700)(10)}{300} = V_2 \]
\[ 90 = V_2 \]

Kick volume will be 90 bbl at the surface.

Some examples of when to use Boyle’s Law are listed below:
- Accumulator sizing
- Kick volume
- Gas migration and expansion

**Kick Pressure at Depth of Interest**

The pressure at the top of a gas kick at a Depth of Interest (DOI) can provide useful information during well control operations. Several simplifying assumptions can be made to make the calculations simpler and more relevant for field usage. The following formulas come from Abel et al, *Firefighting and Blowout Control*. These calculations are intended to provide an estimated value to assist with field operations. If the assumptions do not fit the given situation, a more rigorous approach may be warranted.

The assumptions associated with the following calculations apply for both circulation methods and are:
- Assumes a single gas bubble influx that stays as a single bubble to the surface.
- There is no solubility of the gas into the mud
- There is no geometry change in the well
- The density of the gas is ignored along with temperature

The following equation can be used to estimate the pressure at the top of the gas bubble at a specified DOI using the **Driller’s Method** for circulation:
\[ P_{DOI} = \frac{B}{2} + \left[ \frac{B}{2} + C \right]^{\frac{1}{2}} \]

\[ B = \text{BHP} - 0.052 \times \text{MW}_0 \times (\text{TVD}_{KZ} - \text{TVD}_{DOI}) \]

\[ \text{BHP} = \text{SIDPP} + (0.052 \times \text{TVD}_{KZ} \times \text{MW}_0) \]

\[ C = \frac{0.052 \times \text{MW}_0 \times \text{BHP} \times \text{Vol}_K}{\text{ACF}} \]

Where

- \( P_{DOI} \) = Pressure at Depth of Interest, psi
- \( \text{BHP} \) = Bottom-hole pressure, psi
- \( \text{MW}_0 \) = Original Fluid Weight, ppg
- \( \text{TVD}_{KZ} \) = True Vertical Depth of the Kick Zone, ft
- \( \text{TVD}_{DOI} \) = True Vertical Depth of the DOI, ft
- \( \text{SIDPP} \) = Shut In Drillpipe Pressure, psi
- \( \text{Vol}_K \) = Initial Pit Gain or Kick Volume, bbl
- \( \text{ACF} \) = Annular Capacity Factor, bbl/ft

The following equation can be used to estimate the pressure at the top of the gas bubble at a specified DOI using the **Engineer's Method** for circulation:

\[ P_{DOI} = \frac{A}{2} + \left[ \frac{A}{2} + E \right]^{\frac{1}{2}} \]

\[ A = \text{BHP} + 0.052[\text{L} \times (\text{MW}_K - \text{MW}_0) - \text{MW}_K \times (\text{TVD}_{KZ} - \text{TVD}_{DOI})] \]

\[ \text{BHP} = \text{SIDPP} + (0.052 \times \text{TVD}_{KZ} \times \text{MW}_0) \]

\[ E = \frac{0.052 \times \text{MW}_K \times \text{BHP} \times \text{Vol}_K}{\text{ACF}} \]

\[ \text{L} = \frac{\text{Vol}_{DS}}{\text{ACF}} \]

Where

- \( P_{DOI} \) = Pressure at Depth of Interest, psi
- \( \text{BHP} \) = Bottom-hole pressure, psi
- \( \text{L} \) = Height of the Drill String Volume of Original Mud Weight in the Annulus, ft
- \( \text{MW}_K \) = Kill Mud Weight, ppg
- \( \text{MW}_0 \) = Original Mud Weight, ppg
- \( \text{TVD}_{KZ} \) = True Vertical Depth of the Kick Zone, ft
- \( \text{TVD}_{DOI} \) = True Vertical Depth of the DOI, ft
- \( \text{SIDPP} \) = Shut In Drillpipe Pressure, psi
- \( \text{Vol}_K \) = Initial Pit Gain or Kick Volume, bbl
- \( \text{Vol}_{DS} \) = Drill String Calculated Volume, bbl
- \( \text{ACF} \) = Annular Capacity Factor, bbl/ft
Kick Volume at Depth of Interest

The following two graphs provide a means for a rough estimation of surface casing pressure when a 0.5 ppg kick has been taken. Assumptions were made in order to create these graphs. One assumption made is the annulus size of 8.5 in x 5 in. Another assumption is the TVD value for each chart was assumed to be 7000 ft and 8500 ft respectively. To estimate surface casing pressure by using the chart, begin at the pit gain value on the vertical axis. Trace that value to the corresponding fluid weight line, depending on the fluid weight that is currently in the well. Trace from the fluid weight curve down to the horizontal axis to find an estimation for surface casing pressure. These charts will provide an estimation for surface casing pressure only if the well in question is of a similar kick size, wellbore geometry, depth, and fluid weight.
The equations below can be used to calculate for the kick volume at a depth of interest. Use the Kick Pressure at Depth of Interest formulas to solve for pressure at the depth of interest (P_{DOI}) when either using the Driller’s Method or Engineer’s Method. The following equations are to be used after calculating P_{DOI}.

Use Boyle’s Law to solve for kick volume:

\[ P_1 V_1 = P_2 V_2 \]
\[ P_{BHP} V_{PitGain} = P_{DOI} V_{DOI} \]
\[ \frac{P_{BHP} V_{PitGain}}{P_{DOI}} = V_{DOI} \]

Where

- \( P_{BHP} \) = Bottom-hole pressure, psi
- \( V_{PitGain} \) = Initial pit gain caused by kick, bbl
- \( P_{DOI} \) = Pressure at the depth of investigation, psi
- \( V_{DOI} \) = Kick volume at the depth of investigation, bbl
The “U-Tube” calculation is a simple way to calculate pressure at any point in the wellbore where fluid densities are known. To better illustrate this point, the figure below displays a U-tube containing water and open to the atmosphere.

Calculating the pressure at any point within the wellbore is simply the sum of the pressures above that point. Pressure is a function of vertical depth and fluid density. For example, to calculate the pressure at point A in the tube would be the sum of the hydrostatic pressure of the water column above that point, and the pressure at the surface of the tube. Since the tube is open to atmospheric pressure, we can assume there is no surface pressure being added to the U-tube system. To calculate what the pressure value would be, use the equation provided below.

\[ P_{\text{point}} = P_{\text{surface}} + 0.052 \times MW \times \text{depth} \]

*Where*

- \( P_{\text{point}} \) = the pressure at a given point in the wellbore, psi
- \( P_{\text{surface}} \) = the surface pressure of the well. This is known as the surface component, psi
- \( MW \) = the fluid density within the wellbore, ppg
- \( 0.052 \times \rho \times \text{depth} \) = the hydrostatic component, psi

Using the given information and above equation:

\[ P_{A&B} = 0 + 0.052 \times 8.33 \times 1000 \]
\[ P_{A&B} = 433.16 \text{ psi} \]

The figure above displays points A and B at the same depth. Points A and B would have the same pressure as no inputs would change during the calculation. However, as displayed in the figure below, when a fluid with a different density is added, the pressures in the tube change.

In order to better depict an actual wellbore, one side of the tube will represent the drillpipe while the other represents the annulus, and the tube is closed on either end. The U-Tube contains a 9.6 ppg mud on the drillpipe side to 10,000 ft TVD, and the annulus contains water (8.33 ppg) from surface to 7,500 ft.
ft with the 9.6 ppg mud to TD. The water and mud column in the annulus produce a lower hydrostatic pressure than the uniform mud column in the drillpipe. Thus, the annulus is underbalanced. For the fluid columns to be balanced, a surface pressure must exist on the annulus side. This is a result of the differing hydrostatic pressures exerted by the varying fluid densities in each column.

To calculate what to expect as the surface pressure (SICP), first the BHP must be known. The example below calculates the BHP and SICP using the data provided in the diagram.

Illustration displays effects of U-Tube on surface pressure.

\[
BHP = 0.052 \times 9.6 \times 10,000
\]

\[
BHP = 4992 \text{ psi}
\]

\[
SICP = BHP - 0.052 \times (8.33 \times 7500 + 9.6 \times 2500)
\]

\[
SICP = 495 \text{ psi}
\]

Where

\[
BHP = \text{Bottom-hole Pressure, psi}
\]

\[
HP = \text{hydrostatic pressure at a given point, psi}
\]

\[
SICP = \text{Shut In Casing Pressure, psi}
\]

The example above displays the importance of adding surface pressure to balance a U-Tube. Having different fluid densities throughout the well produces a different hydrostatic pressure to act against the formation. If the hydrostatic pressure is too low, it causes the well to be underbalanced to the formation and may induce a kick. Maintaining a constant BHP is imperative to any well control operation and can be done by manipulating surface pressure.
The diagram below depicts the U-Tube diagram from above with the same data, but as a typical wellbore schematic. This is done to illustrate how the characteristics of a U-Tube translate to a wellbore diagram.

Wellbore diagram displaying effects of U-Tube on surface pressure.

**Gas Migration**

Gas Migration Formula:

\[ H_m = \frac{P_2 - P_1}{0.052 \times MW} \]

\[ G_m = \frac{H_m}{\Delta t} \]

Where

- \(H_m\) = height of migration, ft
- \(P_1\) = initial SICP
- \(P_2\) = final SICP
- \(G_m\) = gas migration rate, ft/hr
- \(\Delta t\) = time interval from \(P_1\) to \(P_2\), hrs
- \(MW\) = Fluid Weight, ppg

Assumptions associated with the formula:
- No fluids lost, closed wellbore system
- No volume change in the gas bubble
  - No height change in the bubble
  - Consistent well geometry
  - The fluid through which the migration is occurring is incompressible
- No temperature change

**Gas Flow Equations**

Estimating the gas flow rate from a well can be beneficial in a number of situations. Practical applications in which field personnel find the estimated gas flow rate from a well useful include the following:
• Kick circulation
• Mud gas separator performance
• Blowout control

There are numerous variables that are needed to determine the gas flow rate from a well accurately. However, knowing the many variables involved is rarely possible. Therefore assumptions must be used to make best estimate guesses.

**Choke Flow Equation**

The equation used to determine the gas flow rate through a choke found on several sites in an internet research is as follows:

\[
Q = CA(gkd_p)^{0.5} \left( \frac{2}{k+1} \right)^{\frac{k+1}{2k-2}}
\]

Where
- \( Q \) = gas flow rate, lb/s
- \( C \) = choke coefficient (usually 0.72)
- \( A \) = choke area, ft\(^2\)
- \( g = 32.3 \text{ ft/s}^2 \)
- \( k = \text{gas specific heat ratio} \)
- \( d = \text{gas density at upstream pressure, lb/ft}^3 \)
- \( p = \text{upstream pressure lb/ft}^2 \)

The Gas Flow Through Choke graph uses the following assumptions and shows the flow for 3 different choke sizes.
- gas specific heat ratio = 1.27
- surface gas density = 0.458 lb/ft\(^3\)
- choke coefficient = 0.72

The upstream gas density was calculated assuming a \( z = 0.8 \) and gas temperature = 85°F.

**Estimate from Flame Length**

There are several equations that are used to calculate the gas flow rate from the length of a flame. The calculations are for single exit low pressure flares.

The API has a flame length calculation in its API Standard 521 as follows:

\[
f_l = 0.0604Q^{0.4776}
\]

Where
- \( f_l \) = flame length, ft
- \( Q \) = heat release rate, BTU/hr

This equation is for sub-sonic flow rates such as those found on a mud-gas separator vent line. Sonic velocity flow occurs whenever the vent line exit pressure is approximately 1.8 times greater than the downstream pressure. This is ±26 psig for a typical natural gas flow to the atmosphere. This situation can occur whenever a well is flowing through a diverter system.

The Flame Length vs. Gas Flow Rate graph shows the gas flow rate for 2 different gas quality values (BTU/scf).
Gas Dispersion

Gas Dispersion in blowout situations is important for a number of reasons.

- Safety of personnel at the site
- Safety of the general public near the site
- Environmental considerations

Gas plume modeling calculations can be performed to determine gas concentrations from a blowout. These programs take into account the weather and surrounding terrain to determine concentration of gas in the surrounding area. The resulting concentration profiles can usually be plotted on a map. These maps are very useful in well control response management.

Computer programs can also be used to calculate the heat flux (radian heat) if the well is on fire. It is important to remember that heat flux is different than temperature. Heat flux is the amount of energy acting on an area. This is what exposed skin feels.

Explosive Limits

An explosion in the oilfield is usually understood as sudden release of energy. Detonation is a fire in which the flame front travels at the speed of sound. Deflagration is a fire that burns at sub-sonic speed.

Lower Explosive Limit (LEL) and Lower Flammability Limit (LFL) are generally the same term. Methane is assumed to be the main component of natural gas. Therefore, the term (LEL) commonly used in the oilfield refers to the LEL for methane. The LEL in air for methane is 5%. This means that if the atmosphere contains 5% by volume of gas an explosion will occur in the presence of a heat source.

The Upper Explosive Limit (UEL) in air for methane is 15%. Concentrations above this limit will not burn because there is not sufficient oxygen available to support combustion even if a heat source is present.

Gas detectors read a percentage of the LEL. A 10% LEL reading calculates to be 0.5% methane in the air. This is well below the LEL. However, this percentage of LEL is generally considered too high for working.

The LEL and UEL for compounds commonly found in the oilfield are given in the following table:

<table>
<thead>
<tr>
<th>Compound</th>
<th>LEL %</th>
<th>UEL%</th>
</tr>
</thead>
<tbody>
<tr>
<td>Kerosene</td>
<td>0.6</td>
<td>4.9</td>
</tr>
<tr>
<td>Diesel</td>
<td>0.6</td>
<td>7.5</td>
</tr>
<tr>
<td>Gasoline</td>
<td>1.4</td>
<td>7.6</td>
</tr>
<tr>
<td>Butane</td>
<td>1.6</td>
<td>8.4</td>
</tr>
<tr>
<td>Propane</td>
<td>2.1</td>
<td>9.5</td>
</tr>
<tr>
<td>Methane</td>
<td>5.0</td>
<td>15.0</td>
</tr>
<tr>
<td>Methanol</td>
<td>6.0</td>
<td>36.0</td>
</tr>
<tr>
<td>Hydrogen Sulfide</td>
<td>4.3</td>
<td>46.0</td>
</tr>
</tbody>
</table>

**Balanced Plug**

Balanced plugs can be cement, barite or some other fluid that is spotted with a work string at a specific location within a wellbore. The “balanced” term implies that the hydrostatic pressures in the annulus, and inside the pipe, are the same at equal vertical depths.

When properly designed, the plug should remain in place after pumping and not move due to fluid imbalance. The work string can be left in place or pulled from the plug.

Assumptions with the following formulas:

- There is no geometry changes in the pipe or casing.
- Does not account for tool joints.
- Assumes no excess in plug volumes

**General Procedure:**

1. Select the plug height.
2. Calculate the volume for the plug:
   a. Inside the pipe
   b. In the casing by pipe annulus
3. Select the height of the spacer.
4. Calculate the volume of the spacer:
   a. Inside the pipe
   b. In the casing by pipe annulus
5. Calculate the volume of displacement.

The plug volume is calculated as follows:

\[
Plug \ Vol_{pipe} = \frac{(ID_{pipe}^2)(h)}{1029.41}
\]

\[
Plug \ Vol_{Ann} = \frac{(ID_{CSG}^2 - OD_{pipe}^2)(h)}{1029.41}
\]

\[
Total \ Plug \ Vol = Plug \ Vol_{pipe} + Plug \ Vol_{Ann}
\]

The spacer volumes are calculated as follows:

\[
Spacer \ Vol_{pipe} = \frac{(ID_{pipe}^2)(h)}{1029.41}
\]

\[
Spacer \ Vol_{Ann} = \frac{(ID_{CSG}^2 - OD_{pipe}^2)(h)}{1029.41}
\]

The volume of displacement is calculated as follows:

\[
Dis \ Vol_{pipe} = \frac{(ID_{pipe}^2)(MD_{Top \ of \ Plug})}{1029.41} - Spacer \ Vol_{pipe}
\]

The final plug height after removal of the pipe is:

\[
H_F = \frac{(Total \ Plug \ Vol)(1029.41)}{ID_{CSG}^2}
\]

*Where*

- **Plug Vol** = plug volume, bbls
- **Spacer Vol** = spacer volume, bbls
Concepts to remember:
- Spacers need to be balanced (same density).
- Displacement fluid needs to be balanced with remaining wellbore fluids.
- Displacement volume can be reduced to allow the plug to “fall” into place and allow dry pipe at the surface.

Bullheading

The term bullheading implies that a well is shut-in and fluids are being pumped into the wellbore and causing additional wellbore fluids to exit at a given point.

Bullheading can be completed at slow rates, although it is most desirable to pump at a rate that is sufficient to exceed the rate of gas migration and effectively “sweep” the wellbore of any gas.

The dominant factor in bullheading is the hydrostatic exchange that occurs between the pumped and exiting fluids being displaced from the well. Generally, it is beneficial to calculate the pump pressure schedule for a bullheading operation.

Bullheading Formula:

\[
CF = \frac{ID^2}{1029.41} \quad \text{or} \quad \frac{ID^2 - OD^2}{1029.41}
\]

\[
h = \frac{Vol}{CF}
\]

\[
\Delta P_{bbl} = (h)(MW_m - MW_w)(0.052)
\]

Where

- \( CF \) = Capacity Factor for the flow path, bbls/ft
- \( ID \) = Internal diameter of pipe, in
- \( OD \) = Outer diameter of pipe, in
- \( h \) = height of the pumped fluid per bbl pumped, ft
- \( \rho_m \) = density of pumped fluid, ppg
- \( \rho_w \) = density of well fluid, ppg
- \( \Delta P_{bbl} \) = Surface pressure change from bullheading per bbl of pumped fluid, psi

Assumptions:
- Formula does NOT account for pressure build-up in the wellbore, only the hydrostatic exchange between the pumped and wellbore fluids.

Important Concepts to Remember:
- Bullheading generally results in fracturing the wellbore, but not in ALL cases.
  - Fracturing will often occur near the last casing shoe because that is generally the weakest exposed formation.
- Wells with long open-hole sections are poor candidates because the kill fluid typically only makes it to the casing shoe, or highest weak zone in the well.
The optimum pump rate should be greater than the rate of gas migration to ensure minimal gas in the well after pumping.

**Stripping**

Stripping is defined as running pipe into a wellbore with surface pressure present, without the use of an outside force (i.e. the pipe falls in the well due to its weight). Stripping can be completed with the use of:

- An annular BOP
- Annular to ram BOP
- Ram to Ram BOP
- Rotating Control Device (RCD) or "rotating head"

**Important Concepts to remember:**

- Stripping is “tripping” pipe with surface pressure present in the “pipe heavy” condition.
- When stripping with an annular BOP, a stripping bottle in the annular hydraulic circuit can assist in reducing the wear/tear on the annular elastomer.
- Casing pressure should be held constant by bleeding fluid from the well while stripping in the hole. The volume of fluids bled should be compared to the calculated value of the actual pipe that is being inserted.

### Hydrogen Sulfide (H₂S)

**Common facts about H₂S:**

- Molecular Weight = 34.08
- Specific Gravity = 1.1767 (Air = 1.00)
- Typically measure in Parts-Per-Million (ppm)
- Conversion of ppm into a percentage (%):
  \[
  \frac{ppm}{10,000} = \% 
  \]
- Percentage conversion into ppm:
  \[
  ppm = (\%)(10,000)
  \]
- Immediately Dangerous to Life and Health (IDLH) limit is set by OSHA at a concentration of 100 ppm
- Rapid unconsciousness and death at 700 ppm
- Flammability range: Volume % in air mixture
  - Lower = 4.30%
  - Upper = 46.0%
- Burning H₂S produces SO₂ (Sulfur Dioxide) which also poses serious health risks, including death in larger concentrations.

\[
2H_2S + 3O_2 \rightarrow 2SO_2 + 2H_2O
\]

**Barite Plugs**

Barite plugs have been used in well control situations to slow down or stop a well flow. These situations are usually underground crossflows. The intent of setting a barite plug is provide a mechanical barrier to stop the flow. The barrier is
intended to be a non-permeable bridge at (or near) the flowing formation.

- Specific density of pure barite mineral is 4.48 g/cc
- Specific gravity of oilfield barite is generally considered 4.2. Some barite can have a specific gravity as low as 4.1.
- Specific volume of 4.2 sg barite is 0.0286 gal/lb = 2.86 gal/100# sack.

**Barite Plug "Rules of Thumb":**

- Tends to work better in a gas flow situation. The intent is to have the gas lift the carrier fluid out and have the barite settle to form the plug.
- Batch mix the plug for pumping and keep it moving to prevent the barite from settling at the surface.
- Most barite plugs are mixed to a slurry density of 18.0–21.0 ppg.
- A thinner is typically applied to the mixture to further aid in barite settling.
- Do not stop pumping the plug until it is in place. Stopping the movement of the plug may allow it to settle at an undesired location.
- Typically, suspension agents are not used in the fluid mixture as the intent is to allow the barite to settle out.
- Pilot test the mixtures for the best results and to ensure that the barite will settle sufficiently.
- Engage the assistance of a specialist when pumping barite pills. Experience will generally always add value to any operations when special techniques are applied.
- In many cases, 2 or more barite plugs are needed to stop the flow.

Caution is always advised when using this type of technique. The consequences to further operations need to be considered in the event that the plug sets in an undesired location, or the plug is unsuccessful at stopping the flow. It is possible for further well intervention operations to be limited and/or compromised from the application of a barite plug.

The table below displays the properties of a 50 bbl barite plug for varying densities.

<table>
<thead>
<tr>
<th>Density</th>
<th>Water</th>
<th>Barite</th>
<th>Total Slurry</th>
<th>Settled Volume</th>
</tr>
</thead>
<tbody>
<tr>
<td>18.0 ppg</td>
<td>50 bbl</td>
<td>410 sx</td>
<td>77 bbl</td>
<td>27 bbl</td>
</tr>
<tr>
<td>19.0 ppg</td>
<td>50 bbl</td>
<td>490 sx</td>
<td>83 bbl</td>
<td>33 bbl</td>
</tr>
<tr>
<td>20.0 ppg</td>
<td>50 bbl</td>
<td>570 sx</td>
<td>89 bbl</td>
<td>39 bbl</td>
</tr>
<tr>
<td>21.0 ppg</td>
<td>50 bbl</td>
<td>665 sx</td>
<td>95 bbl</td>
<td>45 bbl</td>
</tr>
</tbody>
</table>

The formula for mixing a barite plug with water and barite only is as follows:

\[
V = \frac{14.7 \times (MW_{plug} - 8.33)}{35 - MW_{plug}}
\]

**Where**

\[
V = \text{Sacks of barite/bbl water} \\
MW_{plug} = \text{Barite plug density, ppg}
\]
Stuck Pipe
Stuck pipe typically falls into one of the following categories:
- Differentially stuck
- Mechanically stuck

Sonic Stuck Pipe Log
In a well control situation, it is generally not recommended to move the pipe through a BOP. Pipe movement through a BOP can cause the sealing element to fail, which is not acceptable. Most free-point tools require the stuck string to be moved while tools are in the pipe. A sonic stuck pipe log is generally preferred in a situation where a BOP is closed because no pipe movement is required.

The theory behind the tool is the same as a Cement Bond Log (CBL). The amplitude that is measured by the tool indicates whether the pipe is free or not. Typically, a free pipe baseline is established and compared to shifts in the amplitude measurement to identify areas where the pipe is likely stuck.

Considerations for well control situations over a conventional free-point tool:
- Log does not require the movement of the pipe to determine a stuck point.
  - Pipe movement through the BOP in a well control event should be avoided if possible.
- Sonic log can determine multiple stuck points as opposed to only the shallowest point behind the pipe with free-point tools.
- The presence of gas behind a pipe string may be detected due to “cycle skip” in the log.

Pipe Stretch Calculations
The formulas below can be used to determine the stuck point based on the properties of steel and a measured length change (elastic deformation of steel) due to a known force. In other words, the equations calculate the shallowest point where a string of pipe is stuck. The differential force is created by movement of the string.

\[
\text{Differential Force} = \text{Weight}_1 - \text{Weight}_2
\]
\[
\text{Area}_{\text{Steel}} = 0.7854 \times (OD^2 - ID^2)
\]
\[
C_{\text{FP}} = \text{Area}_{\text{Steel}} \times 2500
\]
\[
L_F = \frac{\text{Stretch} \times C_{\text{FP}}}{\text{Differential Force} \div 1000}
\]

Where
- \(\text{Weight}_1\) = Initial weight indicator reading, lbf
- \(\text{Weight}_2\) = Final weight indicator reading, lbf
- \(\text{Area}_{\text{Steel}}\) = Cross-sectional area of the pipe, in\(^2\)
- \(C_{\text{FP}}\) = Free-point Constant
- \(\text{Stretch}\) = Measured stretch from \(\text{Weight}_1\) to \(\text{Weight}_2\), in
- \(L_F\) = Length of Free Pipe, ft
Oilfield brines are mostly used as completion fluids. There are six common brines used in the field.

<table>
<thead>
<tr>
<th>Brines</th>
<th>Abbreviation</th>
<th>Density ppg</th>
</tr>
</thead>
<tbody>
<tr>
<td>Sodium Chloride</td>
<td>NaCl</td>
<td>8.4-10.0</td>
</tr>
<tr>
<td>Potassium Chloride</td>
<td>KCl</td>
<td>8.4-9.7</td>
</tr>
<tr>
<td>Calcium Chloride</td>
<td>CaCl₂</td>
<td>8.4-11.6</td>
</tr>
<tr>
<td>Sodium Bromide</td>
<td>NaBr</td>
<td>8.4-12.7</td>
</tr>
<tr>
<td>Calcium Bromide</td>
<td>CaBr₂</td>
<td>8.4-15.2</td>
</tr>
<tr>
<td>Zinc Bromide</td>
<td>ZnBr₂</td>
<td>Up to 20.2</td>
</tr>
</tbody>
</table>

Many brines above 11.6 ppg are combinations of two or more of these fluids. Heavy brines such as zinc bromide can be used as "spike" fluids to increase the density of other brines.

**Temperature and Pressure Correction**

The surface density of brines used in the oilfield will have different density when they are placed in the well depending on the temperature and pressure. The formulas to calculate the density change depend on many factors:

- Type of brine
- Temperature
- Pressure

Higher temperature results in a reduction of the brine density. The temperature correction factor has a wide range of 0.17-0.528 ppg/100°F depending on the source. Choosing the correct correction factors for the given variables depends on the source.

API RP 13J Testing of Heavy Brines offers the following equation for pressure and temperature corrections:

\[
d_{\text{avg}} = \frac{\left(2000 - (0.052 \times c_p \times TVD)\right) d_{\text{surf}} + [10 \times c_T \times (T_{\text{surf}} - BHT)]}{2000 - (0.104 \times c_p \times TVD)}
\]

**Where**

- \(d_{\text{avg}}\) = average brine density, ppg
- \(d_{\text{surf}}\) = surface density, ppg
- \(T_{\text{surf}}\) = surface temperature, °F
- \(BHT\) = bottom hole temperature, °F
- \(TVD\) = true vertical depth, ft
Temperature and Pressure Correction Factors

<table>
<thead>
<tr>
<th>Brine</th>
<th>Temperature Factor, ( c_T^{*} ) ppg/100°F</th>
<th>Pressure Factor, ( c_p^{**} ) ppg/1000 psi</th>
</tr>
</thead>
<tbody>
<tr>
<td>NaCl</td>
<td>9.49</td>
<td>0.24</td>
</tr>
<tr>
<td>CaCl₂</td>
<td>11.46</td>
<td>0.27</td>
</tr>
<tr>
<td>NaBr</td>
<td>12.48</td>
<td>0.33</td>
</tr>
<tr>
<td>CaBr₂</td>
<td>14.30</td>
<td>0.36</td>
</tr>
<tr>
<td>ZnBr₂/CaBr₂/ CaCl₂</td>
<td>16.01</td>
<td>0.36</td>
</tr>
<tr>
<td>ZnBr₂/CaBr₂/ CaBr₂</td>
<td>19.27</td>
<td>0.48</td>
</tr>
</tbody>
</table>

* \( c_T \) measured at 12,000 psi with \( \Delta T = 76°-198° \) F
** \( c_p \) measures at 198°F with \( \Delta p = 1000-10,000 \) psi

A comparison of the measured surface density vs. the effective wellbore density for a well 12,000' TVD with a BHT of 250°F is shown in the following graph.
The assumed surface temperature for this graph is 70° F.

**Temperature Correction**

The website [www.drillingformulas.com](http://www.drillingformulas.com) offers the following equation for a temperature only correction.

\[
 d_{surf} = d_{avg} + (T_{avg} - T_{surf}) \times T_{factor}
\]

Where

- \( d_{surf} \) = surface density, ppg
- \( d_{avg} \) = average density, ppg
- \( T_{avg} \) = average wellbore temperature, °F
- \( T_{surf} \) = surface temperature, °F

The effective density values calculated with this formula are very close to the values calculated using the API 13J equation. This illustrates the pressure correction is small and can often be discounted.

**Best Practices for Brine Use**

There are several items of note when using brines in the field.

- Heavy brines are corrosive and can be dangerous to personnel if mishandled. All brines should be used with caution and the brine MSDS should be available and consulted before working with the fluid.
• The required PPE for handling and working with brines should be available for all personnel at all times.
• Brines will dehydrate material in which they come in contact. Rubber gloves and boots are recommended.
• Open pits should be covered to keep rainfall from cutting the brine density in the pits.
• All elastomers should be compatible for the brine in use.
• Brines should be stored in clean tanks. The brine tanks should not be share a common manifold with fresh water storage tanks if possible.
• Heavy brines stored in tall, square-sided frac tanks may cause the frac tank to bulge or rupture. Store heavy brines in round tanks if possible.

**Horizontal Considerations**

Horizontal wells are a significant portion of the wells drilled on land. These wells often have lateral sections that are 40% (or greater) of the total depth.

**Drillpipe Schedule**

Scheduling kill mud weight (KMW) to the bit for the Engineer's Method or second circulation of the Driller's Method must account for killing wells with horizontal sections. The conventional pressure reduction schedule is assumed to be a straight line from the surface to the bit. The value calculated for the Final Circulating Pressure (FCP) is still valid but following a conventional straight line schedule from the surface to the bit will not result in a constant bottom-hole pressure.

The graph shows how the actual drillpipe pressure should be handled versus the conventional schedule that is used in vertical and directional wells.

The easiest way to handle this phenomenon is to circulate out the kick using the Driller's Method. Once the kick has been removed,
in theory, the KMW can be circulated into place using a constant casing pressure. However, if there is gas trapped in the lateral that is circulated out while displacing the well with KMW, the constant casing pressure method should not be used for the displacement. A drillpipe pressure schedule that accounts for KMW reaching the well TVD before reaching the bit such as in the chart should be used.

**Casing Pressure**
Horizontal wells that experience kicks have certain characteristics regarding the casing pressure.

- When a kick is taken, a portion of the casing pressure is due to the U-tube between the fluid in the drillstring and the lighter fluid (gas) in the annulus. When the gas is in the lateral part of the hole, the U-tube does not exist. In theory it is possible to have a lateral filled with gas and 0 psi on the casing pressure gauge. A kick swabbed into the lateral may not be detected as there is no casing pressure when the well is shut in.
- Another characteristic of the lack of the U-tube effect is that when a kick is taken in the lateral, the SIDP and SICP may be very close. This can lead to a misdiagnosis of the kick fluid being assumed to be water (or "dead" oil).
- Expansion of the gas while circulating out the kick is a vital element in maintaining a constant bottom hole pressure. This expansion occurs when the kick is moving up the hole (change in TVD) and therefore the casing pressure will show little change until the gas is circulated into the vertical section of the well. Since there is little expansion of the gas while it is in the lateral, the pit gain and casing pressure while circulating out the kick not vary significantly until it is in the vertical section of the well.

**Gas in the Lateral**
Trapped gas in the lateral section of a horizontal well may be present after kill circulations, or trips. Tips to remember that are associated with trapped gas are as follows.

- Gas migration is due to gas buoyancy in the fluid in the well. If the gas is in the lateral part of the hole, the gas migration rate can be extremely low or non-existent. This often results in trip gas.
- Trapped gas in the lateral near the "heal" can be displaced into the vertical portion of the hole while tripping into the well. This type of kick can be masked as if pipe displacement volumes while tripping in to the well are not monitored.
- When oil or synthetic base mud is used gas in the lateral can be solubilized in the mud while circulating. Once the gas/mud mixture pressure goes below its bubble point the gas can break out of solution very quickly. This is usually in the upper part of the hole. This unloading phenomenon can have severe consequences and can be experienced after tripping into the well.

**Frac Bashing**
Frac bashing has led to several serious well control events and blowouts. Some of these were due to poor cement jobs in the horizontal that resulted in pressure migration from the frac into shallower production wells.

Pressure from the offset well frac job can cause a significant kick in a drilling or workover situation. Many of these type of kicks
can be mitigated by bleeding off (flowback) the well that is being fracked. Contingency planning for possible frac bashing from an offset well should be done whenever offset frac jobs are planned.

**Hot Tapping**

Hot tapping is defined as a method used to obtain access to a pressurized tubular or vessel. This is generally completed using a bit to drill into a tubular under pressure in a controlled manner.

The main components of a hot tapping system are:

- **Saddle** – assembly that seals on the vessel to be tapped.
- **Seal** – UHMW seal or other variation.
- **Hot tap unit** – drilling assembly
  - Hand, air or hydraulic operated
  - Size and pressure rating varies
- **Pressurizing device**
  - Hand pump or small air/hydraulic pump

**General Procedure for hot tapping operations:**

1. Install the saddle on the pressurized vessel.
2. Install a working valve on the saddle.
3. Install the hot tap unit on the working valve and pressure test the unit seals, saddle seal and the working valve.
4. Leave suitable pressure on the unit for making the tap to indicate that pressure communication has been established.
5. Stroke in the hot tap bit and drill a hole in the pressurized vessel.
6. Retract the hot tap bit and close the working valve.
7. Bleed off the pressure on the hot tap unit and proceed with the intervention.

**Freeze Operations**

Freeze operations can be used to establish an ice plug for a pressure barrier when other devices are not generally available.

The main components of a hot tapping system are:

- **New working valve**
- **Valve drilling unit**
  - Air or hydraulic operated bit motor
  - Hand operated drilling assembly movement
- **Pressurizing device**
  - Hand pump or small air/hydraulic pump

**General Procedure for valve drilling operations:**

1. Install a working valve on the malfunctioned valve to be drilled.
2. Install the valve drilling unit on the working valve and pressure test the unit seals, all connections, and the working valve.
3. Leave suitable pressure on the unit for proper indication that pressure communication has been established.
4. Drill out the valve gate to full drift.
5. Retract the bit/mill and close the working valve.
6. Bleed off the pressure and remove the valve drilling unit and proceed with intervention.
Gate Valve Drilling

Valve drilling is a method used to obtain access through a malfunctioned valve. The valve may be fully closed, or partially open.

The main components of a hot tapping system are:
- New working valve
- Valve drilling unit
  - Air or hydraulic operated bit motor
  - Hand operated drilling assembly movement
- Pressurizing device
  - Hand pump or small air/hydraulic pump

General Procedure for valve drilling operations:
- Install a working valve on the malfunctioned valve to be drilled.
- Install the valve drilling unit on the working valve and pressure test the unit seals, all connections, and the working valve.
- Leave suitable pressure on the unit for proper indication that pressure communication has been established.
- Drill out the valve gate to full drift.
- Retract the bit/mill and close the working valve.
- Bleed off the pressure and remove the valve drilling unit and proceed with intervention.

Gate Valve Data

The following tables display the number of turns to operate each valve size at their rated working pressure for various gate valve models.

<table>
<thead>
<tr>
<th>Size, in</th>
<th>Cameron Model FC</th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Rated Working Pressure, psi</td>
<td>10000</td>
<td>15000</td>
</tr>
<tr>
<td>1(\frac{13}{16})</td>
<td>12(\frac{1}{2})</td>
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<tr>
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<td>12(\frac{1}{2})</td>
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<tr>
<td>2(\frac{9}{16})</td>
<td>15(\frac{3}{4})</td>
<td>15(\frac{3}{4})</td>
<td></td>
</tr>
<tr>
<td>3(\frac{1}{16})</td>
<td>18(\frac{1}{4})</td>
<td>15(\frac{3}{4})</td>
<td></td>
</tr>
<tr>
<td>4(\frac{1}{16})</td>
<td>23(\frac{1}{4})</td>
<td>-</td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Size, in</th>
<th>WKM Model M</th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Rated Working Pressure, psi</td>
<td>2000</td>
<td>3000</td>
<td>5000</td>
</tr>
<tr>
<td>2(\frac{1}{16})</td>
<td>14</td>
<td>14</td>
<td>14</td>
<td></td>
</tr>
<tr>
<td>2(\frac{9}{16})</td>
<td>16(\frac{1}{2})</td>
<td>16(\frac{1}{2})</td>
<td>16(\frac{1}{2})</td>
<td></td>
</tr>
<tr>
<td>3(\frac{1}{8})</td>
<td>20(\frac{3}{4})</td>
<td>20(\frac{3}{4})</td>
<td>20(\frac{3}{4})</td>
<td></td>
</tr>
<tr>
<td>4(\frac{1}{16})</td>
<td>24(\frac{3}{4})</td>
<td>24(\frac{3}{4})</td>
<td>24(\frac{3}{4})</td>
<td></td>
</tr>
<tr>
<td>5(\frac{1}{8})</td>
<td>30(\frac{1}{4})</td>
<td>30(\frac{1}{4})</td>
<td>30(\frac{1}{4})</td>
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</tr>
<tr>
<td>7(\frac{1}{16})</td>
<td>39(\frac{1}{4})</td>
<td>39(\frac{1}{4})</td>
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</tbody>
</table>

<table>
<thead>
<tr>
<th>Size, in</th>
<th>WKM Model M1</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Rated Working Pressure, psi</td>
<td>10000</td>
</tr>
<tr>
<td>7(\frac{1}{16})</td>
<td>17(\frac{3}{4})</td>
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</table>
### WKM Model M2

<table>
<thead>
<tr>
<th>Size, in</th>
<th>Rated Working Pressure, psi</th>
</tr>
</thead>
<tbody>
<tr>
<td>$4\frac{1}{16}$</td>
<td>$9\frac{5}{8}$</td>
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</table>

### WKM Model M3

<table>
<thead>
<tr>
<th>Size, in</th>
<th>Rated Working Pressure, psi</th>
</tr>
</thead>
<tbody>
<tr>
<td>$5\frac{7}{8}$</td>
<td>$11\frac{3}{4}$</td>
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</tbody>
</table>

### WKM Model M4

<table>
<thead>
<tr>
<th>Size, in</th>
<th>Rated Working Pressure, psi</th>
</tr>
</thead>
<tbody>
<tr>
<td>$7\frac{1}{16}$</td>
<td>$39 \frac{1}{4}$</td>
</tr>
</tbody>
</table>

#### Blowout Response Actions

The initial reactions to a blowout are critical for remediation efforts and for the protection of personnel. The following is a list of some basic actions that can be helpful if there is a blowout occurring:

- **DO NOT** attempt to resolve the situation. Evacuate all personnel immediately. Personnel safety is the priority and cannot be jeopardized in any manner.
- Secure the location and **DO NOT** let anyone approach the well or location area.
  - Generally, a safe zone will be established in pre-planning.
  - If not, the safe zone should be established where there is no risk to personnel from the wellbore effluents, heat, etc.
- Notify the company as directed in the company Emergency Response Plan (ERP).
  - The plan is **NOT** a technical solution guide to a well control event.
  - The plan is **IS** an organizational guide for the response of a company.
  - The plan should identify the local governmental authorities that need to be notified and who within the organization will complete the notification process.
- Contact Well Control Specialists for assistance.
  - Well control personnel are familiar with the issues and risks involved with a well control event.
  - **Blowout Engineers 24-hour Emergency Line:** 1-888-505-6346
- Collect data related to the event. This will be critical for a prompt and proper response.
  - Develop a chronological timeline for actions leading up to the event and actions and activities during the post-event period.
  - Keep accurate notes (times and descriptions) after the event for any changes or notable changes with the well.
o Make note of any harmful or potentially dangerous substances on or around the well location.
o Interview personnel involved in the event, when applicable, to gain as much information as possible.
• Begin pollution containment around the site if it is deemed safe to do so.
o If there are liquids associated with the well effluent, containment berms can often be a temporary solution to contain or minimize the spread of pollutants from the site.
• Await the arrival of well control personnel and company personnel for assistance before attempting to complete any intervention on the well.

Blowout Intervention Phases
Most blowouts involve four distinct phases to complete the remediation efforts and fully resolve the event. The severity of the event can dictate the complexity and length of these phases for individual events.
The phases are as follows:

1. Blowout Assessment and Data Gathering
2. Debris Removal and Site Preparation
3. Capping/Diverting
4. Kill and Wellbore Recovery

Blowout Assessment and Data Gathering
The assessment phase of a blowout is crucial to ensure that the best response for the given situation can be implemented. There is not a “standard” action that is best suited for all well control events. Each event should be adequately assessed, no matter how similar it may appear to be to a past event.

Data gathering must be a dedicated portion of the response effort to plan and effective solution. Relevant well data can assist well control personnel in the development of the BEST plan to resolve the situation at hand. Without accurate data, the duration of the event may extend beyond the time needed to resolve the event, adding to the overall costs of the project.

Debris Removal and Site Preparation
This phase can often be very lengthy, depending on the severity of the event. Many well control events require extensive debris removal and site excavation to allow for remediation. The length of this phase will depend heavily on the situation and the type of intervention that will be required to eventually regain control of the well.

This phase will generally require heavy equipment with seasoned operators. Some of the equipment that can be expected are as follows:

• D7/D8 bulldozers with winch packages
  o The winch package is required for use with Athey wagons.
• Large excavators
  o Standard reach
  o Long reach
• Cranes
  o Hydraulic
  o Lattice boom
  o Crawlers
• Specialized firefighting equipment
  o Fire pumps

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- Athey wagons
- Cold cutting equipment
- Abrasive cutters
- High pressure pumps and blenders

**Capping / Diverting**

The capping diverting phase is when the well flow is contained and redirected, or stopped at the surface exit point. There are many aspects surrounding a blowout that will need to be evaluated when considering what method will be used to cap a well, and if the well can be shut-in or diverted. Some of these are:

- Shut-in surface pressures
- Wellhead integrity
- New wellhead installation for capping
- Wellbore integrity
- Surface pollution

Well control service providers should provide advice on the proper control methods for a well control event. This advice is generally based on extensive experience with a variety of scenarios.

**Well Kill and Wellbore Recovery**

This is the phase in the project when the well is ultimately brought under control. There are multiple kill techniques that may be used based on a wide range of scenarios. Some common kill methods used with blowouts are:

- Dynamic kills
- Bullheading
- Momentum kills
- Lube and Bleed

Several of these kill techniques involve the use of "live well" intervention tools. The most common of these are:

- Snubbing
- Coiled Tubing (CT)

The final kill selection will generally involve the following decision points:

- End goal for the wellbore:
  - Recovery to a producing well
  - Plug and abandonment (P&A)
- Control method: shut-in or diverted
- Intervention tools
- Wellbore parameters

**Blowout Equipment Needs**

The following lists contain items that are typically required for a major blowout intervention project. This list can be used early in the event to initiate the blowout response.

**Construction Equipment**

- Bulldozers
- Excavator
- Cranes (lattice boom and/or hydraulic)
- Forklifts
- Man-lifts
- Fabrication material (steel pip, angle tin etc.)
- Air Compressor (185 cfm)
- Light Towers
- Trash pumps
• Pneumatic tools (impact wrench hammer winch etc.)

Firefighting Equipment
• Firefighting water storage and transfer
• Athey wagon
• Hydraulic Athey wagon
• Debris hook and rake
• Firefighting pumps
• Venturi tube
• Diamond wire saw
• Guillotine saw
• Rail Mill
• Abrasive jet cutter
• Hydraulic shears
• Exothermic cutting rods
• In-place machining tools (thread cutter, ring groove surfacing etc.)
• Lathe Cutter

Well Control Equipment
• Wellhead (SOW or slip type) and valves
• BOP capping stack
• Choke manifolds
• High pressure pumps
• Hot tap, valve drill and freeze
• Fabrication materials and personnel
Relief Well
In addition to conventional drilling needs the following items are required for relief well drilling.
- Proximity ranging tools
- Kill spool and valves
- Kill pumping equipment and pump iron
- Kill fluid storage and transfer

Post Blowout Well Recovery
Equipment needed to recover or plug the blowout includes the following:
- Snubbing equipment
- Coiled tubing equipment
- Cementing units
- Wireline/slickline equipment and production logging tools
- Plugs, cement retainers
- Fluid tanks, mixing and pumping equipment

Relief Well Drilling
Relief well planning has received a lot of interest in the industry in the last few years. However, very few relief wells are actually drilled to kill a blowout. Therefore, the number of industry personnel that have real relief well experience is limited.

A brief outline of a relief well design process for a blowout is as follows:
- Determine the intercept depth
- Determine the blowout flow rate
- Calculate the required dynamic kill rate at depth and hydraulics
- Determine the hole size needed to deliver the dynamic kill rate at the intercept depth
- Develop the proximity ranging plan
- Define the relief well surface location
- Design the directional plan based on the surface location, ranging plan and the intercept
- Design the relief well casing program

This approach yields the precision needed to drill the relief well to a point in which hydraulic communication can be achieved and the blowout well can be killed.

Ranging
Proximity ranging for relief well for a blowout is complicated by the inability to access the target well. Therefore, the ranging method is confined to only using the relief wellbore. There are currently 3 methods used to locate a target from a relief well.
- Active ranging uses a wireline to inject current in the earth. The current subsequently flows through the relief well casing (or drill string). Special magnetometers in the ranging tool detect current and distance and direction to the target is determined.
- Passive ranging uses the interference an MWD experiences when it is in close proximity to steel (relief well casing) to determine the distance and direction to the target.
- Acoustic ranging uses sound transmitters and receivers in a wireline tool to see a reflection of a sound wave caused by the target well. The distance and direction to the reflection is calculated.
The ranging vendor should be involved in the relief well design process from the beginning so that the directional plan can be developed with the chosen ranging method. The ranging plan is the primary mitigation for early intercept while drilling when the EOU for the relief well and the target well overlap.

The following table gives a comparison of the different ranging methods.

<table>
<thead>
<tr>
<th>Ranging Methods Compared</th>
<th>Method</th>
<th>Accuracy</th>
<th>Range</th>
<th>Cost</th>
<th>Deployment</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Active</td>
<td>high</td>
<td>&lt;150’</td>
<td>high</td>
<td>wireline</td>
</tr>
<tr>
<td></td>
<td>Passive</td>
<td>low</td>
<td>&lt;30’</td>
<td>low</td>
<td>drill string</td>
</tr>
<tr>
<td></td>
<td>Acoustic</td>
<td>moderate</td>
<td>&lt;100’</td>
<td>high</td>
<td>wireline</td>
</tr>
</tbody>
</table>

The distances given here are considered the practical separation and are not what the ranging vendors advertise.

**Directional Drilling**

Standard directional drilling techniques and tools are used to drill a relief well. Conventional mud motor or rotary steerable systems can be used.

Special attention to the Ellipses of Uncertainty (EOU) is important when designing the relief well. Survey management calculations to reduce the EOU of the target and relief wells should be considered.

The directional plan is adjusted whenever the ranging tools have identified the relative position between the wells.

**Intercept**

The intercept point for a blowout is vital in that it has to be deep enough so that a dynamic kill will be successful in killing the well.

There are 2 basic intercept methods.

- Direct communication to the target by milling into the target well casing and/or drillstring. This method is reliable and has become the technique of choice due to the ability to have greater control over the operation when establishing hydraulic communication between the relief well and target well. A traditional mud motor and MWD BHA is used with the mill.

- Drilling into the blowout reservoir near the target well and establishing communication to the target through the rock matrix or fracture. Drilling into the reservoir can lead to hole stability problems often due to the low flowing bottom-hole pressure in the formation that is blowing out. There are numerous other issues that usually make this type of intercept problematic.

Drilling to intercept is done by steering relative to the high side as the MWD magnetometers are affected by the proximity to the relief well and the resulting azimuth to the target well is unreliable.

**Well Kill**

Well kill operations begin when adequate hydraulic communication between the relief well and target well are sufficiently established. All personnel should be on station at this time as there is usually no delay between establishing communication and pumping the kill. Monitoring the annulus in the relief well is critical to determine when hydraulic communication has been established.
The kill is usually pumped down the annulus of the relief well. The drill string can also be used but the pump rate down this path is generally limited to the drilling circulation rate.

**Relief Well Best Practices**

The following is a short list of best practices for relief well drilling.

- Set a kill casing string immediately above the intercept point to ensure hole stability while drilling to intercept and pumping the kill.
- Add a kill spool in the relief well BOP stack for kill pumping.
- Ensure that all personnel are well rehearsed for the kill operation.
- Shut in the relief well while pumping the kill.
- Use the drill string in the relief well as a bottom-hole pressure gauge by pumping down the string at a low rate during the dynamic kill.
- Record all data related to the kill pumping.

**Dynamic Kill**

A dynamic kill is one in which the backpressure on the well to be killed cannot be manipulated. These type kills are mostly performed on blowouts. "Out running the kick" is a common phrase that technically refers to a dynamic kill. However, the dynamic kill process is much more complicated than simply pumping as fast as possible.

The basic principles of a dynamic kill involve a complicated mixing problem. The basic equation for well control also applies to a dynamic kill.

\[
BHP = HP + FP + SP + AP
\]

**Where**

- \(BHP\) = Bottom-hole pressure, psi
- \(HP\) = Hydrostatic Pressure, psi
- \(SP\) = Surface Pressure, psi
- \(FP\) = Friction Pressure, psi
- \(AP\) = Acceleration Pressure, psi

A close look at the terms in this equation provides the following definitions as related to a dynamic kill.

- The hydrostatic pressure is dependent on the density of the kill fluid/blowout fluid mixture
- The surface pressure is due to any surface restrictions at the blowout exit point.
- The friction pressure is dependent on the friction from the kill fluid/blowout fluid mixture
- The acceleration pressure is the kinetic energy term. This pressure is due to the change in velocity of the fluid.

The hydrostatic pressure is the main component of the kill. Determining the mixture density of the kill fluid/blowout fluid is straightforward. If the blowout fluid is gas, the gas density can be calculated at different pressures and temperatures.

The surface pressure component for most dynamic kills is fixed. In conventional well kills like the Driller's or Engineers Methods,
the surface pressure is varied by opening or closing the choke. The ability to manipulate the surface pressure removes the requirement to control the well with a dynamic kill. In most blowouts, the surface pressure is atmospheric pressure. Calculations for the exit pressure of a blowout are relatively easy to make if the flow from the well is sonic.

Acceleration pressure is due to gas expansion as the gas moves up the well to the surface. The velocity change results in a force applied over the exit diameter area. This force is usually low and is often discounted in dynamic kill calculations.

There are four components needed for the dynamic kill calculation.

- The blowout flow rate
- The blowout fluid density
- The kill fluid rate
- The kill fluid density

The blowout flow rate can be calculated. For a gas well, the reservoir Inflow Performance Relationship (IPR) curve establishes a flow rate vs. BHP graphically. The Productivity Index (PI) can also be used. The PI is a straight line ratio of the well production vs. the reservoir pressure drop (bopd/psi or mmscfd/psi). The outflow curve (often called the tubing curve) can also be calculated.

The Forchheimer equation is most often used to generate the IPR curve for dry gas wells. There are several methods used for the outflow curve; average T&z, and Cullender and Smith are the methods that are the most presented in industry literature. The calculations involve integration of the well flowing pressure. When these curves are plotted together, their intersection gives the blowout flow rate and corresponding flowing BHP.

The gas blowout fluid density can be calculated based on gas composition, pressure, temperature and z factor. Various methods use surface or average gas density for steady state calculations. If the well is also producing fluid, the density of the produced fluid needs to be considered.

The kill fluid density and rate are chosen. The kill fluid/blowout fluid mix results in a mixture density. This mixture density is used to calculate the hydrostatic and friction pressures.

Using the gas density at surface conditions will result in a lower mixture density than the actual mixture density. This method is often used to produce the most conservative calculation for the dynamic kill.

When the various flow rates and kill rates are plotted together, all kill solutions that yield a BHP greater that the IPR (or PI) curve are considered valid.

A an example dynamic kill with 13 ppg mud for a 10000’ TVD dry gas well with 9000 psi reservoir pressure blowing out through 9½/8” casing is shown in the flowing graph.
In this example, 40 bpm is the minimum dynamic kill rate since it generates a BHP greater than the IPR FBHP at all gas rates.

It is important to note that there are usually many assumptions that must be made for input into the dynamic kill solution. This is true for the steady state and transient approaches. Experience in calculating and executing dynamic kills for blowouts is valuable in making the correct assumptions.

Computer programs are used to describe the system in transient. These programs simulate the blowout and the dynamic kill as a function of time. The steady state dynamic kill rate calculated in the method shown here agrees with the transient method computer simulations.

**Temperature Logs**

In well control operations, temperature logs are generally used in association with underground blowout (UGBO) diagnostics. Temperature logs can be very useful in the identification of a wellbore fluid flow path, either in the wellbore system or behind a casing string.

Noise logs are often run in conjunction with a temperature log and can be used to support the diagnostic conclusions from the temperature data. It is not necessary to run a noise log if it is not available.

The theory of temperature logs for well control operations is the same as it is for production operations. The flowing fluids in the wellbore change the surrounding temperature profile, based on a number of parameters. If the geothermal (static) temperature...
profile for the well is known, the flowing profile can be compared to identify areas of fluid movement based on temperature change.

The temperature log profile can be impacted by the following:

- Geothermal temperature for the area
- Flow rate
- Type of flowing fluid(s)
- Well geometry
- Duration of flow
- Entry and exit point for flowing fluid(s)
- Wellbore deviation (TVD vs MD)

The following are some general "Rule of Thumb" considerations for temperature logging in well control operations:

- The geothermal profile for the area needs to be understood for the baseline for comparison of the temperature logs.
- The initial down log run is typically the most accurate for temperature comparison, as the data it provides most closely resembles the wellbore state prior to the log being run.
- Heat exchange into the surrounding well from moving fluids is time dependent in the "early-time region". Sufficient time should be allowed for temperature changes to occur before/after logging.
  - It is difficult to allocate a specific time value for the "early-time region" as heat exchange is flowrate dependent. However, it can be defined as the region on the temperature profile that occurs prior to the system reaching a state of thermal equilibrium.

**Underground Blowout**

The generally accepted definition of an underground blowout (UGBO) is the uncontrolled flow of formation fluids from one underground formation into another.

An UGBO can generally be identified by one or more of the following indicators:

- Fluctuations in surface pressure(s)
- Presence of gas to the surface
- Discontinuity between casing and drillpipe pressure responses (i.e. the u-tube is no longer a closed system)
- Increasing casing pressure due to the displacement of drilling/completion fluids with reservoir fluids
- Falling drillpipe fluid level (if the drill string is in the hole)
- Irregular response to conventional well control methods

Most UGBO cases flow from deeper to shallower formations. There are cases where the flow has been from shallow zones into deeper zones, based on pressures associated with the wellbore.

Situations that commonly result in an UGBO are as follows:

- Fracture pressure at the casing shoe (or weakest exposed formation) is exceeded upon shut-in from a kick
- Improper execution of well control techniques that leads to failure of the wellbore
- Gas migration is allowed to occur without intervention that leads to increased pressure within the wellbore and eventually failure
- Induced failure of the wellbore from pumping (bullheading, top kill, etc.)
Casing failure allowing the exposure of weaker formations to excessive pressure
Poor isolation (cement) behind casing allowing the exposure of weaker zones to excessive pressure

Common methods used to kill an UGBO are as follows:

- Dynamic kills
- Reactive pills (gunk, etc.)
- "Sandwich" kills
- Momentum kills

As with any kill operation, several parameters must be either defined or assumed. These are as follows:

- Flow rate of reservoir fluids
- Reservoir fluid properties
- Flow path within the wellbore

A reasonable assumption can typically be reached for the reservoir fluid properties. The flow path and flow rate are the parameters that tend to be misinterpreted in an unsuccessful kill attempt. The flow path can often be well diagnosed by the use of temperature logs. The flow rate can also be estimated by the use of temperature logs, or other diagnostic logging techniques. These techniques are normally sensitive to interpretation and various assumptions.

Pipe Light Calculation

Pipe light conditions exist when the weight of a tubular is less than the force created by a pressure differential acting on that tubular. The principle concept to understand is:

\[ \text{Force} = (\text{Pressure})(\text{Area}) \]

The area of the tubular at the sealing element (where the differential occurs) is to be used for calculations. The sealing element is typically a BOP, RCD or stripping head.

**Pipe light conditions exist if the pressure-area force is greater than the weight of the pipe that is in the wellbore.**

Assumptions associated with the following formulas:

- Sealing element is at the surface where pressure is read.
- Does not consider frictional component associated with the sealing element on the pipe.
- Dry pipe, if fluid is present in the tubular, the weight of the fluid must be considered.

Formulas:

\[ \text{Area} = \frac{\pi}{4}(OD^2) \]

\[ \text{Force}_{P-A} = (\text{Area})(\text{Wellhead Pressure}) \]

\[ W_s = (L)(w_i) \]
Where

Area = pipe area at the sealing element, \( \text{in}^2 \)

OD = Outer Diameter of tubular, \( \text{in} \)

L = length of the work string, \( \text{ft} \)

\( w_i \) = incremental weight of the tubular, \( \text{lbm/ft} \)

\( W_s \) = Total String Weight, \( \text{lbm} \)

\( \text{Force}_{P-A} \) = Pressure-Area force, \( \text{lbf} \)

Concepts to remember:

- Fluid in the tubular will impact the summation of forces in the system.
- Frictional pressure opposes motion and needs to be considered in snubbing force calculations, not necessarily pipe light calculations.
- The area component is typically the most misinterpreted component in the relationship. The area is NOT calculated based on the largest component or tool on the tubular string, it is calculated where the pressure differential occurs.

Snubbing

Snubbing is the process of running tubulars in/out of a well when a pipe light condition exists (Reference pipe light calculation in this book for further explanation). Snubbing units add the external force required to move the tubular in a control manner and overcome the pressure-area force and frictional force generated on a tubular.

Most snubbing unit sizes are referred to in respect to the maximum hook load for the unit. This being the maximum working weight that the unit can lift with the hydraulic circuit at the maximum pressure. The maximum snub load is generally half of the hook load, depending on the actual size of the snubbing jack leg cylinders and pistons.

Example: Hydra Rig 340K Unit
Max hook load = 340,000 lbf, Max Sub Load = ±170,000 lbf

Snub Force Equation:

\[
F_S = F_{P-A} + F_f + F_B - W_s - W_f
\]

Where

\( F_S \) = Snub Force, \( \text{lbf} \)

\( F_{P-A} \) = Pressure-Area Force acting on the pipe, \( \text{lbf} \)

\( F_f \) = frictional force, \( \text{lbf} \)

\( F_B \) = Buoyant force acting on the tubing from wellbore fluids, \( \text{lbf} \)

\( W_s \) = String Weight, \( \text{lbm} \)

\( W_f \) = Weight of fluid in the pipe, \( \text{lbm} \)

Assumptions:

- No drag in the wellbore other than frictional force at the sealing element.
- Equation assumes pipe is run into the well.
Tank Volume and Capacity Calculations

Volume

\[ Volume = Capacity \times \text{Height} \]

Vertical Cylindrical Tanks

Tank Diameter in Feet

\[ \text{Capacity (bbl/ft)} = \frac{\text{Tank Diameter}^2}{7.149} \]
\[ \text{Capacity (bbl/in)} = \frac{\text{Tank Diameter}^2}{85.78} \]

Tank Diameter in Inches

\[ \text{Capacity (bbl/ft)} = \frac{\text{Tank Diameter}^2}{1029.4} \]
\[ \text{Capacity (bbl/in)} = \frac{\text{Tank Diameter}^2}{12,353} \]

Rectangular Tanks

\[ \text{Capacity (bbl/ft)} = 0.178 \times \text{Length} \times \text{Width} \]
\[ \text{Capacity (bbl/in)} = 0.0148 \times \text{Length} \times \text{Width} \]

Horizontal Cylindrical Tanks with Tank Diameter in Inches

\[ Volume = \text{Length} \times \frac{\text{Tank Diameter}^2}{1029.4} \]

Horizontal Cylindrical Tanks with Tank Diameter in Feet

\[ Volume = \text{Length} \times \frac{\text{Tank Diameter}^2}{7.149} \]

Where

Volume = Volume of tank, bbl
Capacity = Capacity of tank, bbl/ft OR bbl/in
Tank Diameter = Diameter of circular tank, ft OR in
Length = Length of rectangular tank, ft
Width = Width of rectangular tank, ft
Typical Frac Tank Volumes
Although there is no standard for frac tank sizing, typical 500 gallon tanks share similar dimensions. Below are the websites for frac tank vendors where specific tank dimensions can be found.

Adler Tank Rentals
http://www.adlertankrentals.com/products/tanks

Dragon Energy Equipment
http://www.dragonenergyequipment.net/tanks/fr-corrugated-wall.html

Frac-n-Vac Tanks
http://www.fracnvac.com/products.html

Clean Harbors
http://www.cleanharbors.com/browse_by_service/waste_disposal/container_management/frac_tanks.html
Blowout Engineers Office Location
8505 Technology Forrest, Suite 101
The Woodlands, TX 77381
1.888.505.6346
www.blowoutengineers.com

Sierra Hamilton Office Locations
www.sierra-hamilton.com

Houston, TX
777 Post Oak Blvd, Suite 400
Houston, TX 77056
1.713.956.0956

Midland, TX
10 Desta Drive, Suite 260 E
Midland, TX 79705
1.432.683.8000

Lafayette, LA
500 Dover Blvd., Suite 310
Lafayette, LA 70503
1.337.984.2603

Oklahoma City, OK
3101 South Lakeside Drive
Oklahoma City, OK 73179
1.405.843.5566

Denver, CO
1580 Lincoln Street, Suite 630
Denver, CO 80203
1.303.542.1853

Morgantown, WV
2603 Cranberry Square
Morgantown, WV 26508
1.304.413.4500

Auburn Energy Management
6160 Warren Parkway, Suite 100
Frisco, TX 75034
1.469.519.2711
www.auburn-energy.com
These contacts act as First Responders to a well control event and can be reached 24 hrs/day for any well control emergency.

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