Well Control Methods

WILD WELL CONTROL

Well Control Methods

Learning Objectives

- You will learn well control circulating techniques and proper responses to change in pressures.
- You will learn circulating well control techniques:
  - Driller's Method
  - Wait and Weight
  - Concurrent
  - Reverse circulation
- You will learn non-circulating well control techniques:
  - Volumetric
    - Lubricate and Bleed
  - Bullheading

Well Control Methods

Overview

- The goal of all well control methods is to safely control the well.
- Circulating well control methods are often referred to as “constant bottom hole” methods as they keep BHP equal to FP preventing additional influx fluids.
- These methods provide for:
  - Removal of kick fluids:
    - *Must* keep BHP ≥ FP to prevent additional kicks.
    - *Must* keep pump running at a *constant* speed.
    - Pressure is regulated with a choke.
  - Replacing the existing fluid with one that has sufficient weight to regain hydrostatic control.

Well Control Methods

Overview

- Common ***circulating*** well control techniques are:
  - Driller's
  - Wait and Weight
  - Concurrent
- These all use the same procedures and only differ when and if a kill weight fluid will be circulated.
- A well is very rarely killed by one circulation due to inefficient fluid displacement in the annulus.

Regulating Pressures

- Bottom hole and surface pressures may be a combination of several factors. These are:
  - Formation pressure
  - Hydrostatic pressure(s)
  - Circulating Friction pressure
  - Choke pressure
- Since FP, HP and circulating friction are fairly constant during the initial stages of well control, the only way to change pressure is by choke manipulation.

Regulating Pressures

- While shut in or circulating a kick with pump at a *constant reduced circulating rate*, pressure is regulated by choke manipulation.
  - To ***decrease*** pressures, open choke slightly:
    - Increase choke orifice diameter.
      - Bleeds off pressure while shut in.
      - Reduces friction across choke while circulating.
  - To ***increase*** pressures, reduce choke orifice size (close choke slightly).
    - Decrease choke orifice diameter.
      - Increases friction across choke while circulating.

Regulating Pressures

- Choke adjustments must be made to maintain proper circulating pressure.
  - If the circulating drillpipe/pump pressure gets too high, estimate the excess amount. Then use the choke reduce or bleed off that amount. Monitor the casing pressure gauge whenever a pressure adjustment is made.
  - If circulating pressure is below the desired value, estimate the needed amount and monitoring the casing pressure gauge, adjust to a more closed position until the adjustment pressure is made.

Regulating Pressures

- Changes in pressure must be made only by using the gauge and not the choke position indicator. (The indicator scale actually only shows the position of the choke and the direction it is moving. It does not represent pressure changes.)
- If pressure on gauge (s) suddenly change, check pump rate and immediately return choke pressure to last reliable value. Make a note of sequence of unregulated pressure changes.

Regulating Pressures

- Choke adjustments depend on the frictional properties of different fluids that go through it.
  - Type of fluid.
  - Rate of fluid flow.
  - Fluid density.
- If these parameters are changed, a drastic change in choke pressure can occur. Such is the case when gas begins to exit across the choke.
  - The choke operator must anticipate this event and be ready to adjust the choke quickly to maintain the back pressure held by the choke. Remember, if choke pressure suddenly decreases, pressure throughout the well will also decrease and an additional influx may occur.
    - Immediately return choke pressure to its last pressure value.
    - Evaluate circulating pressure.
    - Make additional changes if necessary.

Choke Response – Liquid Following Gas

- The choke operator must also anticipate rapid increases in choke pressure. A concern during well control is when liquid (fluid in use), following a gas kick being circulated through the choke, enters the choke.
  - Can cause rapid increase in pressure.

Choke Response – Liquid Following Gas

- If the choke pressure is not immediately adjusted back to the prior value (just before this event), the pressure increase may lead to lost circulation/formation breakdown.
    - Subsea choke and kill lines require additional considerations, as both gas voiding the lines and liquid following the gas must be taken into account.

Choke Response – Lag/Transit Time

- Circulating (pump) and choke (casing) pressures are closely related through the “U-tube”.
- Any changes in circulating rates will affect the entire well.
  - When a change in pressure occurs on one gauge, it will not be immediately reflected on the other gauge.

Choke Response – Lag/Transit Time

- The other gauge “lags” behind as the pressure change transits the U-tube.
  - If a pressure adjustment is made, proper lag time must be allowed in order to get an accurate reading before making unnecessary adjustments.

Choke Response – Lag/Transit Time

- “Rule of thumb”: A lag time of two seconds per 1,000 feet of well length is typically required to transit a pressure pulse in a drilling fluid.
  - Obviously on deeper wells, lag times are longer than ones that are shallow.
  - Compressibility of fluids (e.g., brine vs. gel muds) affect transit time.
- If additional adjustments are made before the pressure is allowed to transit the U-tube, inadequate or unnecessary pressures can result.

Choke Response – Lag/Transit Time

- Proper documentation is a very neglected aspect of well control.
  - In times of potential confusion it is better to have written notes and pressures than to rely on memory.
  - Good notes can show potential complications developing.
  - Provides a record of events.
    - These records can be of use on existing wells if problems/additional kicks occur.
    - Can be of use for future wells.
    - Very useful to help investigate and solve complications.

Choke Response – Lag/Transit Time

- Record pressures, volumes, pit gains and choke adjustments. Jot notes down on what's going on.
- Be accurate!

Commonalities for Circulating Methods

- When kick occurs, shut the well in!
  - Check for leaks in BOP/manifolds, etc.
  - Begin recording SIDPP, SICP, until pressures stabilize, record pit gain.
  - Complete necessary worksheets.
  - Depending on kill method, may begin weighting-up pits.
  - When ready to circulate, hold choke (casing) pressure at its SICP value and ***SLOWLY*** bring pump up to Kill Rate Speed.

Commonalities for Circulating Methods

- Once pump is at kill speed, and casing pressure is at its SICP value, record circulating (pump) pressure.
  - This pressure is the Initial Circulating Pressure, ICP and must be held until when/if kill fluid will be pumped.
  - ICP = SIDPP + KRP
    - Pressure above SIDPP is from pump, if choke pressure is correct.

Simplifying the Initial Phase of Kill Ops

- Pre-operation meeting with all involved personnel. Everyone must know their responsibilities.
- Very good communication between pump and choke operator is necessary.
- The pump should be brought up to speed slowly or in gradual stages to avoid formation damage or complications.
  - On rigs with mechanical pumps, the pump can’t be brought to speed in slow stages because its slow speed is idle and idle is the kill rate. The choke or a bypass should be opened, then the pump engaged. Then, using the choke, adjust choke pressure to previous value.
- Casing pressure should be maintained at a constant pressure while bringing the pump to kill rate speed. As soon as the pump is on line and running at proper kill rate speed, casing pressure must be returned to its correct value.

Simplifying the Initial Phase of Kill Ops

- ICP, which is shown on the circulating pressure gauge, is the pressure needed to circulate a well at a given rate <u>and</u> prevent the well from flowing. *ICP = SIDPP + KRP.*
- If this value does not agree with calculated values a decision must be made.
  - Were the shut in pressures correct, or could they be inaccurate due to gas migration?
  - Are the gauges correct?
  - Are the calculations correct?
  - Was proper start up procedures used?
  - Is the pump at same efficiency as when kill rate pressures taken?
- A decision must be made on what values to use, or shut it down, shut it in, reevaluate shut in pressures and try again.

Simplifying the Initial Phase of Kill Ops

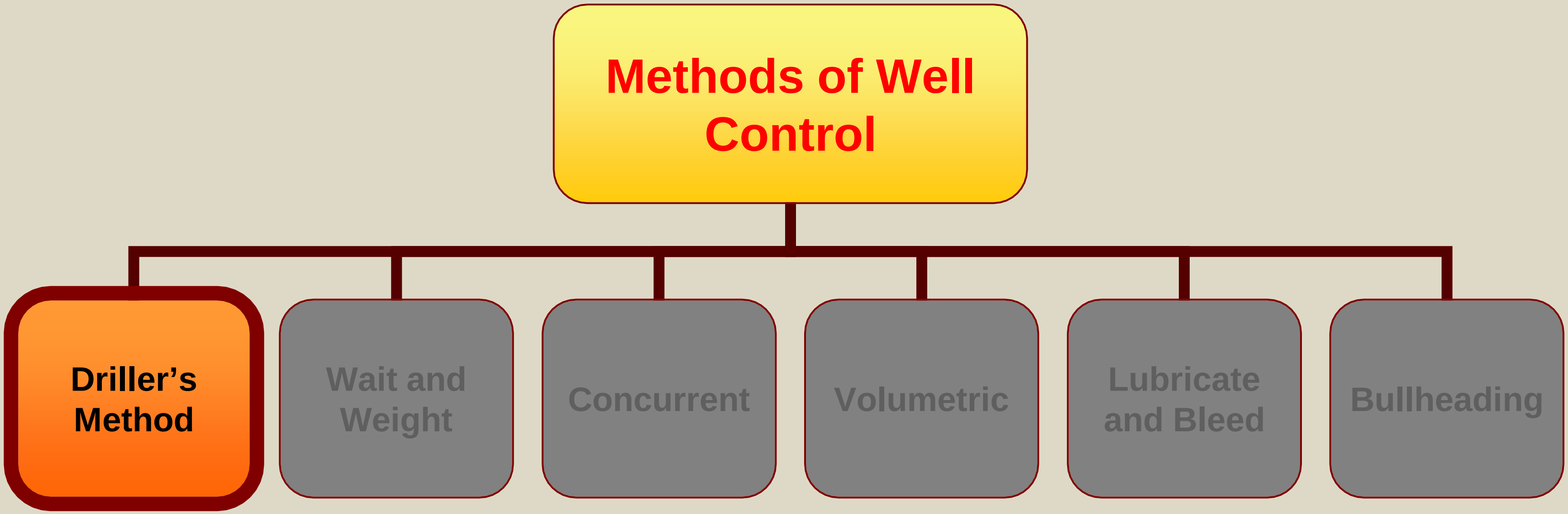
Simplifying the Initial Phase of Kill Ops

Special Operational Well Control Considerations

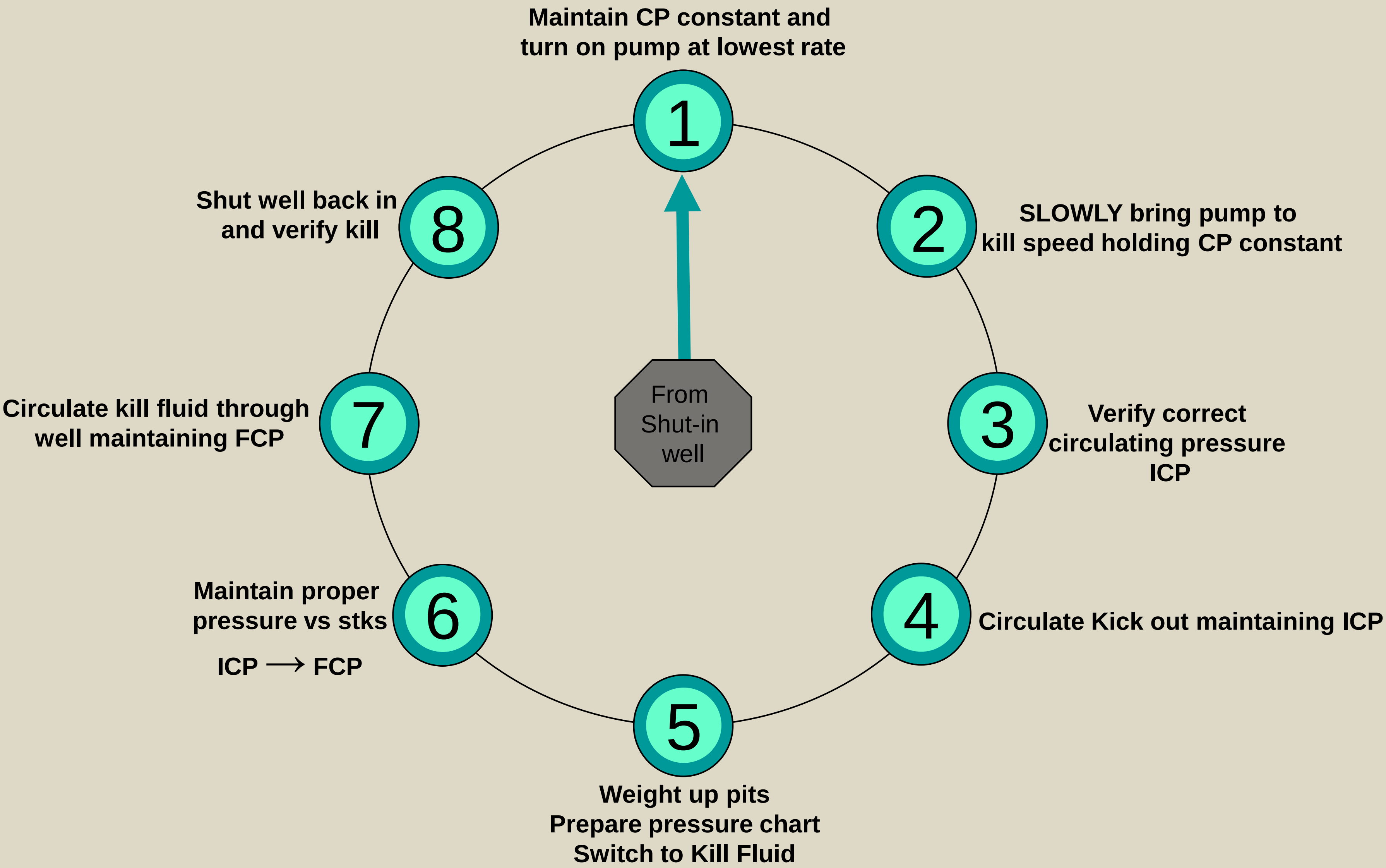
Six Methods of Well Control

- Driller's Method
- Wait and Weight
- Concurrent
- Volumetric
  - Lubricate and Bleed
- Reverse Circulation
- Bullheading

Simplifying the Initial Phase of Kill Ops



Driller's Method Action Sequence



The Driller's Method

- Perhaps the most common method in use today.
- Good for gas kicks with high migration rates that may result in shut-in problems.
- Also used to remove kicks that are swabbed in during a trip out of the hole.
- Used when no weighting material is necessary or available.
- Used when personnel and/or equipment is limited.

**More time to kill the well is needed in this method than other methods. It may cause slightly higher pressure in the annulus than other methods (due to lack of additional HP from Kill Fluid in initial circulation).*

The Driller's Method

The Driller's Method Procedure

Basic Circulation Technique - First Circulation – Removing Kick From Well:

1. Shut-in well after kick.
2. Record kick size and stabilized SIDPP and SICP.
3. ASAP start circulating original mud (fluid) by gradually bringing the pump up to the desired kill rate while using the choke to maintain constant casing pressure at the shut-in value.
4. Pump pressure should be equivalent to calculated ICP. If not equivalent, investigate and recalculate if necessary.
5. Maintaining pump pressure equal to ICP, kick/influx is circulated out of the well, adjusting pressure with choke as required.

The Driller's Method

The Driller's Method Procedure

After Kick Circulated Out – Killing The Well:

6. Continue to circulate from an isolated pit or slowly shut down the pump maintaining pressure on the choke (casing) gauge equivalent to the original SIDPP.
   - Avoid trapping pressure or allowing additional influx if shutting back in.
7. The active system should be weighted up to the pre-determined kill fluid density and circulated in order to regain hydrostatic control.
8. If the well was shut in, start up pump procedures are again used.
9. It is advisable to calculate and use a pressure vs. stroke chart (ICP to FCP) to track the kill fluid and changes in circulating pressures.
10. Circulate the kill fluid to the bit/end of string.

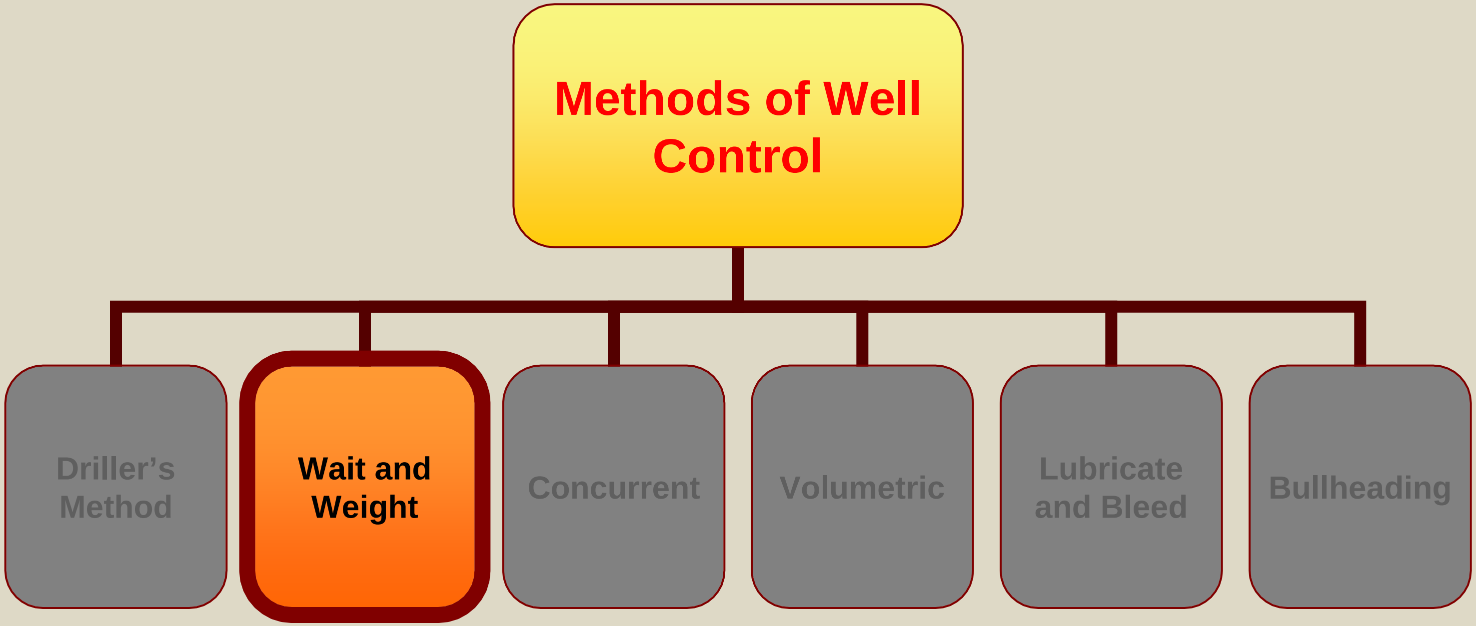
The Driller's Method

The Driller's Method Procedure:

After Kick Circulated Out – Killing The Well:

11. Once kill fluid is at the bit/end of string, FCP should be realized.
    - Circulating pressure should be equivalent to the calculated FCP.
12. Maintain constant FCP circulating pressure until the kill fluid completely fills the well.
    - The gain in HP should necessitate slowly reducing choke pressure.
    - Once the kill fluid reaches surface, the choke should have been fully opened.
13. Shut down pump and check for flow.
14. Close choke and check pressures.
15. If no pressure is noted, open choke (bleeding any trapped pressure), open BOP.

Methods of Well Control



Wait and Weight Method

- The Wait and Weight method kills the kick faster and keeps wellbore and surface pressures lower than any other method.
- Requires good mixing facilities, full crews, and more supervision than most other methods.
- The first calculation that should be done in the Wait and Weight Method is kill fluid density.
- Fluid weight is increased before circulation begins, hence the name Wait and Weight.
- Start up procedures same as Driller's method.3

Wait and Weight Method

- Calculations required for:
  - Kill fluid density
  - ICP and FCP
  - Volume/strokes/time surface to bit/end of string
  - Pressure chart
  - Volume/strokes/time bit to surface
  - Total volume/strokes/time for complete circulation
  - Pressure limitations

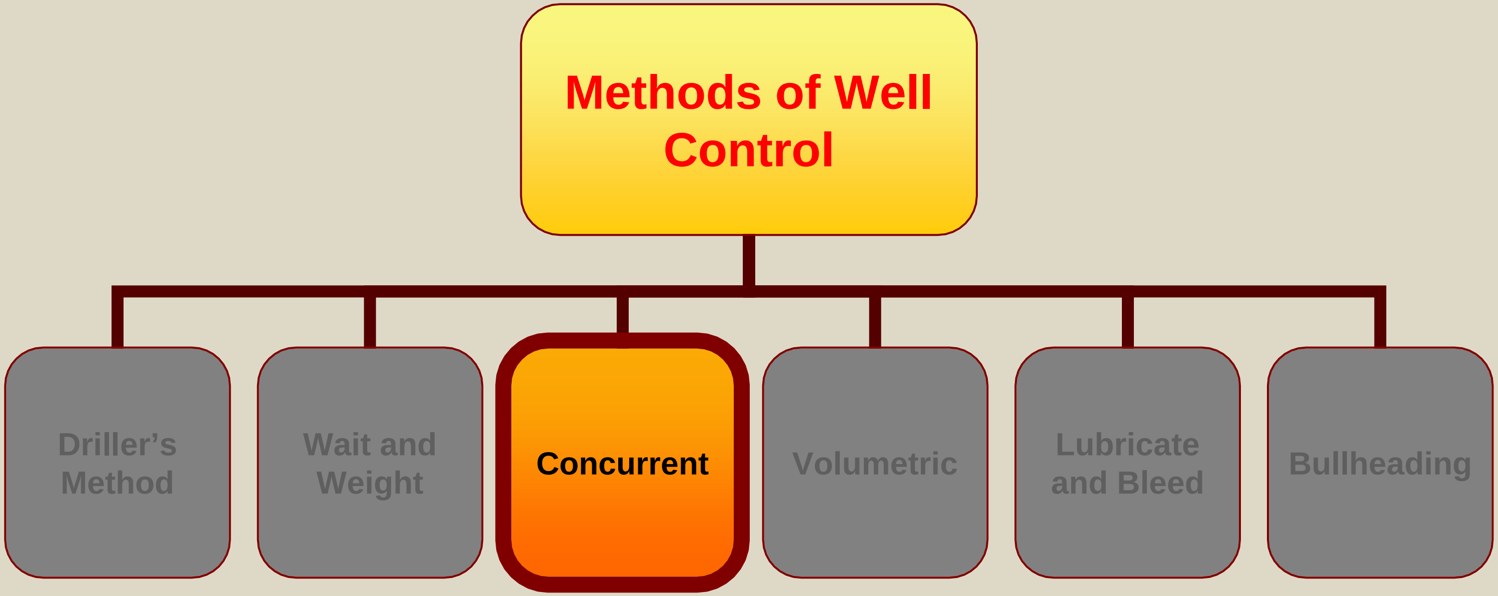
Wait and Weight Method

1. Shut-in well after kick.
2. Record kick size and stabilized SIDPP and SICP, calculate kill fluid density.
3. Pits are weighted up as other calculations are performed.
4. If there are increases in shut-in pressure, the Volumetric Method should be used to bleed off mud/fluid from the annulus to maintain constant stabilized drill pipe/tubing pressure.
5. Once pits are weighted, start circulating kill weight fluid by gradually bringing up the pump up to the kill rate while using the choke to maintain constant casing pressure at the shut-in value. Remember to hold pump rate constant.
6. Circulating pressure should be equivalent to (ICP) Initial Circulating Pressure. If not, investigate and recalculate ICP if necessary.

Wait and Weight Method

7. Follow pressure chart/graph as kill fluid is pumped down the string to bit/end of string.
8. Once kill fluid is at the bit/end of string, FCP should be realized.
   - Circulating pressure should be equivalent to the calculated FCP.
9. Maintain constant FCP circulating pressure until the kill fluid completely fills the well.
   - The gain in HP should necessitate slowly reducing choke pressure.
   - Once the kill fluid reaches surface the choke should have been fully opened.
10. Shut down pump and check for flow.
11. Close choke and check pressures.
12. If no pressure is noted, open choke (bleeding any trapped pressure), open BOP.

Methods of Well Control



Concurrent Method

- Sometimes referred to as the Circulate and Weight Method *or* Slow Weight-Up Method.
  - It involves gradually weighting up fluid while circulating out the kick.
- Additional calculations are required when tracking different fluid weights in the string at irregular intervals.

** Sometimes, crew members are required to record concurrent method data even if this is not the method intended to be used.*

Concurrent Method

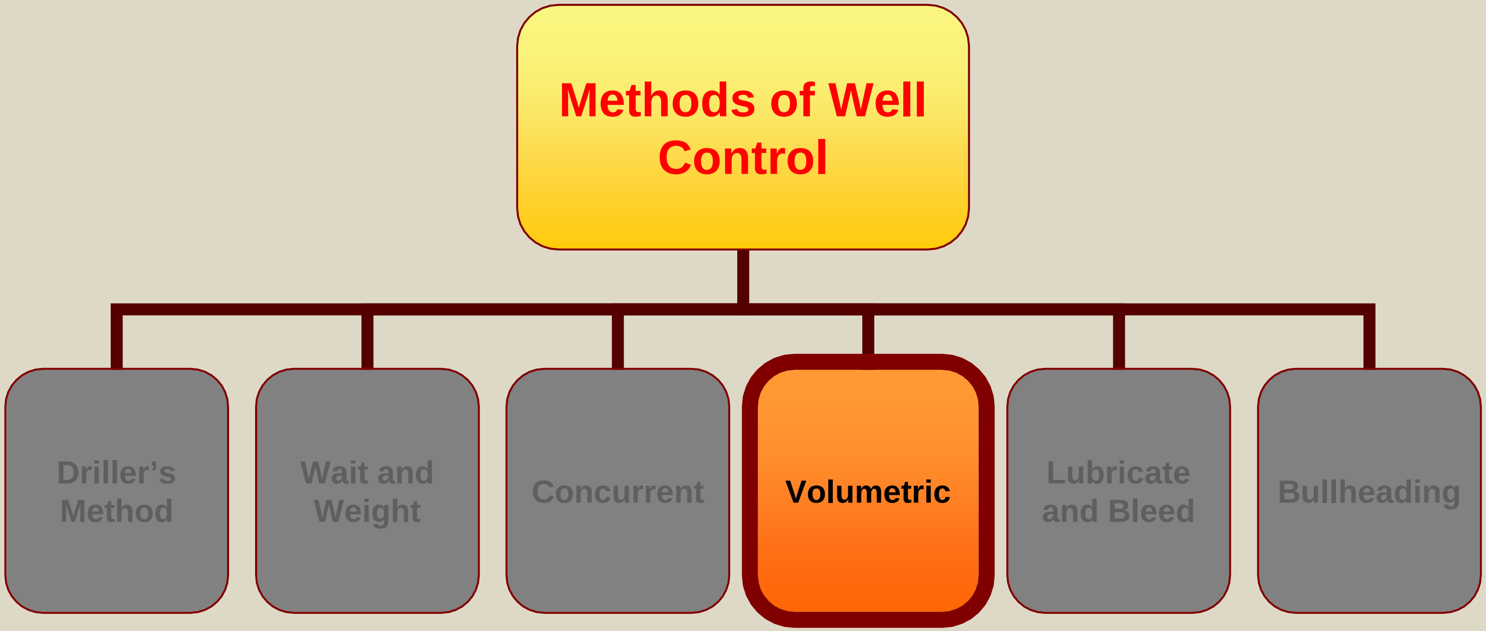
The Concurrent Method Procedure:

1. Shut-in well after kick.
2. Record kick size and stabilized SIDPP and SICP.
3. ASAP start circulating original mud (fluid) by gradually bringing the pump up to the desired kill rate while using the choke to maintain constant casing pressure at the shut-in value.
    - Pump pressure should be equivalent to calculated ICP. If not equivalent, investigate and recalculate if necessary.
4. Mixing operations begin and pits are slowly weighted up and each unit of heavier fluid reported.

Concurrent Method

5. Each interval or unit of increased fluid density is then noted and recorded with the pump stroke count at that time.
   - The change in circulating pressure for the different density is calculated.
   - Once this fluid reaches the bit/end of tubing, circulating pressure is adjusted with the choke by that amount.
6. The kick is circulated out and the fluid in the well continues to be gradually increased.
7. Once the kill fluid is consistent throughout the well, shut down pump and check for flow.
8. Close choke, shut well in and check pressures.
9. If no pressure is noted, open choke (bleeding any trapped pressure), open BOP.

Concurrent Method



Volumetric Method of Well Control

- The volumetric method is a way of allowing controlled expansion of gas during migration.
  - It replaces volume with pressure (or vice versa) to maintain bottomhole pressure that is equal to, or a little higher than BHP, and below the formation fracture pressure.
- With a swabbed in kick, the volumetric method can be used to bring influx to surface and then replace the gas with fluid in order to return the well to normal hydrostatic pressure.
- It is not used to weight up and kill the well.
  - Used to control the well until a circulating method can be implemented.
  - Can be used to regain HP if the existing fluid is adequate and gas is allowed to reach surface.

Volumetric Method of Well Control

- Situations where Volumetric Methods can be used:
  - String is plugged.
  - String is out of the hole.
  - Pumps are not working.
  - String is off bottom.
  - During stripping or snubbing.
  - A shut-in period or repairs to surface equipment.
  - Tubing or packer leak causes casing pressure to develop on production or injection well.
  - A washout in string prevents displacement of kick by one of the circulating methods.
  - In subsea operations only 1 line should be used to prevent gas separation effects..

Volumetric Method of Well Control

- If casing pressure does not increase 30 minutes after a kick is shut in, gas migration is minimal. This means that the Volumetric Method need not be used. However, if casing pressures continues to increase there is a need to initiate Volumetric techniques.
  - Some basic scientific principles must be understood before using the Volumetric Method:
  - <u>Boyle's Law</u> – shows the pressure/volume relationship for gas. It states that if gas is allowed to expand, pressure within the gas will decrease. This is the same concept used by the Volumetric Method in that it allows gas to expand by bleeding off an estimated fluid volume at surface, which results in decreasing of wellbore pressures.

Boyle's Law

P1 V1 = P2 V2

Volumetric Method of Well Control

- Single Bubble Theory – The biggest misconception in well control schools is that the gas enters the well as a "single bubble".
  - In reality it is dispersed as pumping and observance of the kick is noted, then more "pure" kick as the pumps are shut down and well is shut in.
  - It may be many minutes before the kick is actually noted resulting in an annulus filled with influx/regular fluid.
  - So, in reality, a single large kick rarely occurs, and once the well is shut in, the pressures on the casing shoe/weak zone have probably reached it's maximum.
  - This is not to say that MAASP should not be observed, just that it should be considered that the maximum pressure should be based on the latest pressure test of the BOP or casing.

Stripping/Moving Pipe and Volumetric Considerations

- A stripping pressure schedule must be created in order to control pressures during stripping operations while gas is migrating, pipe is moving, and fluid is being bled off at choke.

Lubricate & Bleed (Lubrication)

- The Lubricate & Bleed Method is used when kick fluid reaches the wellhead.
- It is considered a continuation of the Volumetric Method.
- Generally, workover operations more commonly use the Lubricate and Bleed technique because circulating ports in the tubing are plugged, sanded tubing, or circulation is not possible.

Lubricate & Bleed (Lubrication)

- In this method, fluid is pumped into the well on the annulus side.
- Enough time must be allowed for fluid to fall below gas.
- Volume must be precisely measured so hydrostatic pressure gain in the well can be calculated.
- This value increase will then be bled off at surface.

Methods of Well Control

Methods of Well Control

- Driller's Method
- Wait and Weight
- Concurrent
- Volumetric
- **Reverse Circulation**
- Bullheading

Reverse Circulation

- Reverse circulation is the reversal of normal circulation or normal well kill pump direction.
- In reverse circulation, due to friction (APL, ECD) most of the circulating pump pressure is exerted on the annulus.
- Standard start up procedures apply.

**Reverse circulation also has its advantages and disadvantages.*

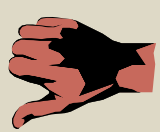
Reverse Circulation

Advantages Of Reverse Circulation

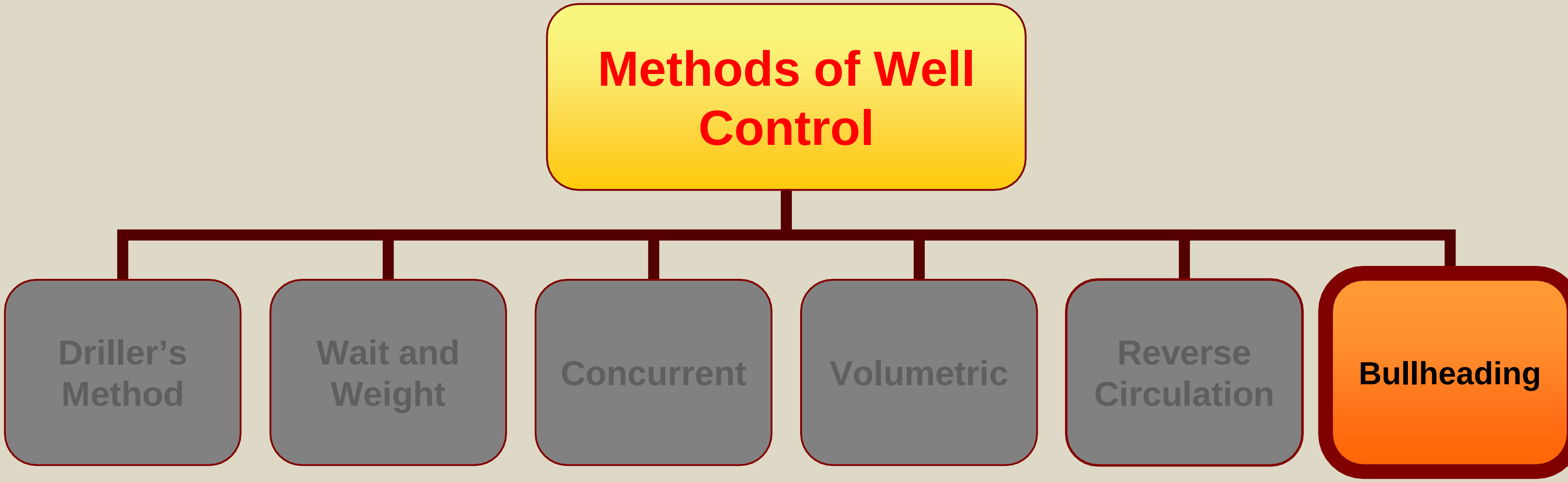
1. It is the quickest method of circulating something to the surface.
2. Gets the problem inside the strongest pipe from the beginning.
3. Generally, the annular fluid is dense enough to maintain control of the formation, which reduces fluid mixing and weighting requirements.

Disadvantages Of Reverse Circulation

1. Higher pressure is placed on formation and casing.
2. Excessive pressure may cause fluid losses/casing and/or formation failures.
3. Not applicable for uses where plugging of circulating ports, bit nozzles of string are possible.
4. Gas filled or multiple densities in tubing may present problems establishing proper circulating rates.



Methods of Well Control



Bullheading

- Bullheading, or deadheading, is often used as a method of killing wells in workover situations.
- Bullheading is only possible when there are no obstructions in the tubing and there can be injection in the formation without exceeding pressure restraints.
- Bullheading involves pumping back well fluid into the reservoir, displacing the tubing or casing with a good amount of kill fluid.

Bullheading

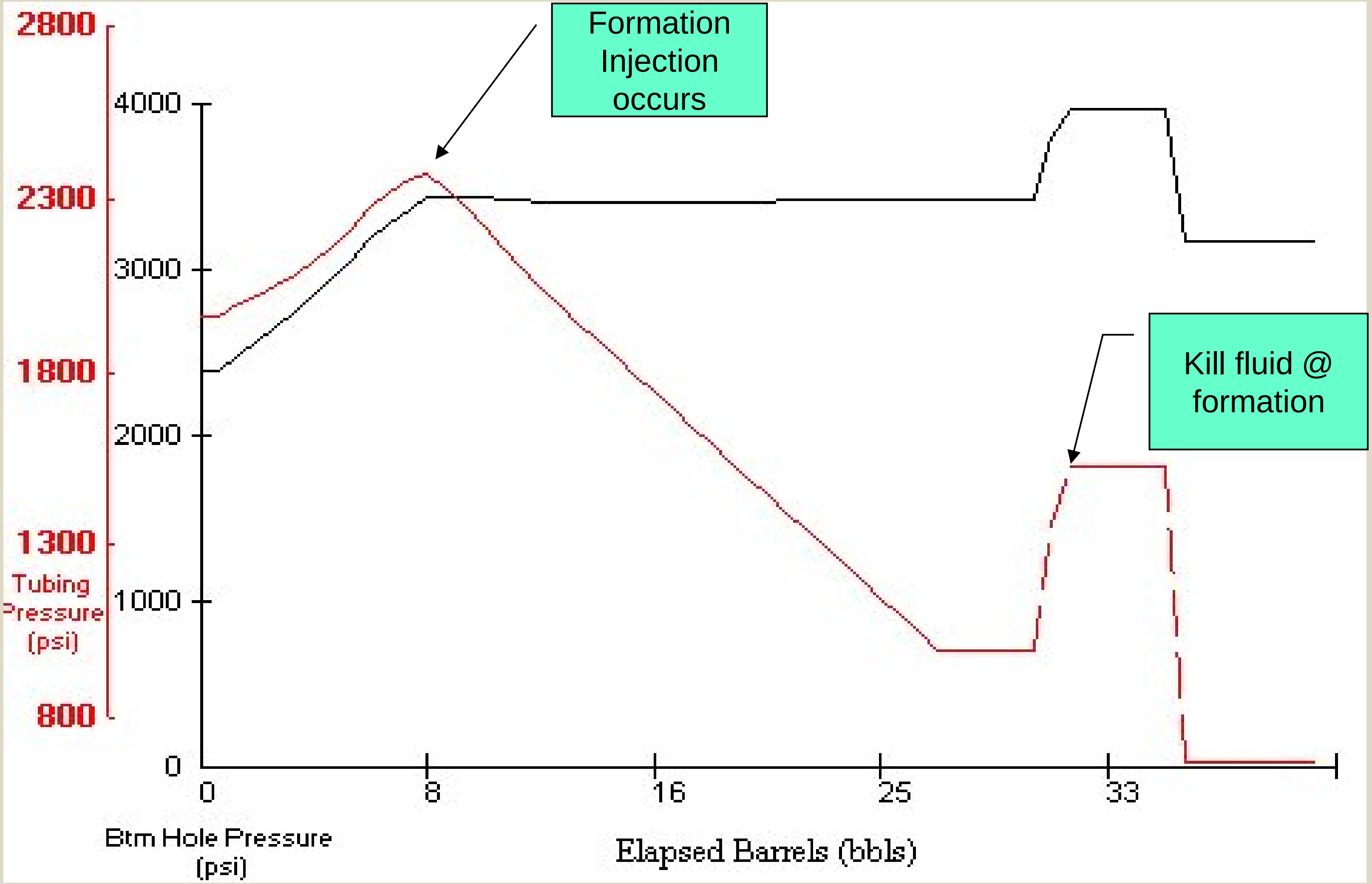
- Complications can make bullheading difficult in certain situations:
  - Sometimes, when bullheading down the tubing, pressure may have to be exerted on the casing in order to prevent the tubing from collapsing. *Both, tubing and casing burst/collapse pressures, should be known and not exceeded.*
  - Formation fracture pressure may have to be exceeded due to low reservoir permeability
  - Gas migration through the "kill fluid" can pose a problem. In this situation, viscosifiers should be added to the kill fluid to minimize the effect of migration.

Bullheading

Bullheading Procedure

1. Well is shut in and formation pressure is calculated. If bullheading down the tubing, maximum pressures should be calculated.
2. Prepare a rough pressure chart of volume pumped versus maximum pressures at surface. Friction and formation pressure must be overcome to achieve injection of the liquid in the tubing back into the formation. If pressures or pump rate is too high, damage to the formation may occur.
3. Once the pumped liquid reaches the formation, an increase in pump pressure may occur. This is due to a non-native fluid injected to the formation.
4. Once the calculated amount of fluid is pumped, shut down, observe pressures. If no pressure increase is observed, bleed off injection pressure and, again, observe. If no pressure change is seen, the well should be dead. Proceed operations *with caution*.

Bullheading



Bullheading

Special Operational Well Control Considerations

- Slimhole
- Air Drilling
- Communications
- Concentric Techniques
- Tubing Limitations
- Multi Lateral/Multi Completion
- Mudcap
- Kicks Off Bottom
  - Stripping
    - Using Annular
- MASP (MAASP)
- UBD/PWD

Air Drilling Well Control

- Air drilling allows a well to flow until the formation is producing at a sufficient rate or conditions are no longer safe.
- Well killing techniques differ with different areas and different accepted practices. Some pump water, some inject air. Some shut the well in completely.
- Areas that perform air drilling techniques are usually limited on water and have formations that do not produce high liquid or gas flow rates.

Air Drilling Well Control

- Most kill techniques involve pumping water down the drillpipe to the bit. This water is pumped at a high rate down the drillstring because:
  - Extreme differences between weight of water being pumped and the formation gases in the annulus.
  - <u>Vacuuming</u> – the well may "U-tube" faster than slower pump rates can keep up.
- The pump may be slowed down in order to avoid an abrupt increase in surge pressure on the pump as the water reaches the end of the string.

Air Drilling Well Control

- After pump rate is decided and fluid has reached the bit, different techniques may be used depending on situation.
  - Technique A:
    - Continue pumping at high rate.
    - When enough water hydrostatic has accumulated in the annulus, the formation flow stops and the well is killed.

Air Drilling Well Control

- Technique B:
  - Circulating through the choke.
  - This will cause more backpressure that may be enough to cease flow in the well.
  - If not enough, a choke technique may be used.

The advantage of using backpressure is that holding backpressure through the choke slows the expansion of gas.

This allows drops of water to fall back downhole, saving water that could be lost when not using backpressure.

Choke Techniques

There are various choke techniques that can be used to maintain the equivalent hydrostatic pressure of water in order to gain control of the well.

- Choke technique 1:
  - When water rounds the bit, choke is closed enough to exert the water’s hydrostatic as backpressure.
  - Water circulates up the hole and backpressure is decreased by the estimated gain in water hydrostatic.
  - However, formation gases also exert hydrostatic pressure, so this must be noted in order to stop the well from pressuring up higher than the equivalent weight of the water used.

Air Drilling Well Control

- Choke Technique 2:
  - Pressure is not applied on choke until the water is believed to be at the casing shoe.
  - Equivalent hydrostatic from shoe to surface is held.
  - Hydrostatic begins to gain above the shoe and the equivalent is bled from the choke.
    - However, the formation fracture or formation strength at the casing shoe is often unknown.
      - This calls for a leak-off test, but it defeats the purpose of air drilling to water the hole and perform the test.
      - Therefore, this technique is not used in many areas.
      - Additionally, the structural integrity of the formation or the strength of the bond between the cement and casing is usually not known or tested.

Mudcap Drilling

- Mudcap drilling is performed:
  - When returns cannot be circulated back to surface.
  - When annulus pressures at surface are nearing operational limits.
  - If extreme drilling fluid loss is anticipated.
  - If capacity of handling fluid at surface is exceeded.
- Mudcap drilling allows for drilling while managing extreme lost circulation in an overpressured area.

As with most procedures, there are advantages and disadvantages to mudcap drilling.

Mudcap Drilling

Advantages Of Mudcap Drilling

1. Allows for drilling while managing extreme lost circulation in an overpressured environment. Therefore, it saves time and money from fighting lost circulation.
2. Easier procedure than flow drilling.
3. Reduces surface pressure on annulus.
4. Minimizes requirements for surface fluid processing equipment.
5. Minimizes hydrocarbons, H_2S at surface, which can be hazardous to the environment.
6. Not as much environmental planning needed as in PWD (Pressure While Drilling).

Disadvantages Of Mudcap Drilling

1. Increases required training/qualification for personnel.
2. More logistical requirements and planning than conventional drilling.
3. More potential for formation damage and more complex drilling/tripping procedures.
4. Higher pressure rotary drilling equipment is required.
5. Higher pump pressure is required, which may result in the need to modify the rig pump or change the pump.
6. More potential for drillstring sticking at point of injection by differential pressure or cutting/packoff.
7. Because well is shut in at surface, drill cutting and fluid samples are unable to be obtained.

Mudcap Drilling

- <u>Pressured Mudcap Drilling Technique</u> – Pressured mudcap drilling permits monitoring of annulus pressure to show any changes downhole. A pressure ranging from 150 to 200 psi is usually held on the choke. Changes in pressures indicate the potential of an influx in the well and/or formation pressure changes.
- <u>Non-pressured Mudcap Drilling Technique</u> – no monitoring of annulus pressures. Used where sub normal pressures are encountered.

Mudcap Drilling

- Floating Mudcap Drilling Technique – A viscous heavy mud “cap” is used to prevent formation flow is utilized. Usually used where a loss zone is encountered and the mudcap used to prevent formation flow.

Multi-Completion and Multilateral Considerations

- Well control is limited to the following when producing from multiple zones:
  - Fluid barriers
  - Mechanical barriers
  - Live well intervention

Slim Hole Considerations

- In slim holes, more than 90% of the hole length is drilled with bit diameters that are smaller than 7”.
- Concerns for slim hole include:
  - High annular friction while pumping can cause fluid losses while circulating. Kill rate speed and pressures must be at a rate slow enough to minimize annular friction.
  - Since the diameter of the hole is smaller, there is a high potential for swabbing. Trip speed at a given depth should be calculated and not exceeded.

Slim Hole Considerations

The same techniques used to detect kicks are used in slimhole operations.

- However, since the hole is smaller, kicks must be detected on a smaller increase in flow, smaller gain in pit or during the earlier stages.
- Prior to and during trips:
  - Always use a trip log sheet.
  - Calculate the pipe displacement accurately.
  - Calculate the theoretical fill.

Slim Hole Considerations

- Measure the trip tank accurately.
- Record the actual values.
- Compare against theoretical values.
- Consider “U-tubing” of the slug affecting several fill-ups.
- Consider a pumpout to no-swab potential depth.

- In addition to kick detection by rig crew, additional equipment can be used to monitor the well. When used, alarms should be set.

Slim Hole Considerations

- Consider using the following:
  - Flow in
  - Standpipe pressure
  - Casing pressure
  - Flow out
  - Mud density in
  - Mud density out
  - Mud gas level
  - Mud level in each tank
  - Depth indicators
  - MWD/LWD tools

Communications

- Operations should not begin until each crew member has received, understands and can perform his/her instructions and duties.
- Any and all changes in duties, from the normal duties, should be cleared, reported and recorded by a supervisor.
- Well control is a team effort, so communication with all personnel involved is critical.

Other Control Techniques

- The use of certain control techniques fluctuates on a case by case basis. More advanced techniques besides the Driller's, Wait and Weight, Concurrent and Volumetric methods include are available.
- If conventional techniques do not regain control of the well the following may be considered:
  - Dynamic and Momentum Kills.

**These techniques should only be used by experienced personnel with expertise in these methods.*

Pressure Charts and Graphs

- A Circulating Pressure Graph shows what happens to circulating/drillpipe pressure as the new heavier mud weight is being pumped down the string.
- A pressure chart shows strokes vs. what circulating pressure to hold at that point.
  - Straightforward and used on most vertical wells for simplicity.
    - Does not account for string geometry, friction per geometrical section and pressure drop across bit nozzles.

Pressure Charts and Graphs

- Column for:
  - **Strokes**. Begin by clearing stroke counter to “0”.
    - End with “strokes to bit/end of tubing”.
    - To use a 10 step chart, divide “strokes to bit/end of tubing” by 10.
  - **Pressure**. Begin with ICP and end with FCP.
    - Use ICP – FCP divided by number of steps (e.g., 10).
    - Start with ICP, and subtract the change of pressure per step.

Pressure Charts and Graphs

Pressure Chart Modifications:

- High angle wells and also those using coiled tubing may have special considerations if the Weight and Wait Method is used.
  - Each section should be taken individually and the change in pressure charted/plotted.
  - The pressure chart may not appear as a typical “straight line” and circulating pressure may actually increase before Final Circulating Pressure is reached.

Maximum Allowable Surface Pressure

- The maximum allowable surface pressure (MASP) must be calculated. The minimum of the following is considered the pressure limitation:
  - Casing Burst Pressure
  - BOP Stack Limits
  - Formation Fracture (pure liquid to weak zone)
- Crew members must be aware not to exceed value if based on casing burst or BOP limits.

Maximum Allowable Surface Pressure

- Casing depth, present and kill fluid density, formation integrity, kick position, and imposed surface pressures are factors that affect this pressure consideration.

Tubing Pressure Limitations

- Internal Yield is the pressure value which, if applied within the tubular, will cause the pipe to burst.
- Some operations must consider burst and collapse limitations of the tubing/string and care taken not to exceed these values.

Formation Pressure Considerations

- Any excess pressure exerted against a formation may cause an increase in time and costs of working over to bring it back to production. Keep pressure to a minimum.
- As kill fluid flows down the production string, the amount of static surface pressure that may be exerted before the damage decreases.
- Circulation friction rises as the kill fluid is pumped down the string, which increases surface pressure and pressure in the tubing.
  - These sudden increases in pressure may cause a burst in the tubing.

UBD/PWD Equipment

- Mud gas separator
- Flow lines
- Gas flare line
- Separation tanks
- Pumps to move oil to frac or storage tanks and circulate fluid back to tanks for reuse.

* *On land locations, lighting is essential at night, especially for the Derrickhand.*

  - UBD/PWD equipment may require additional lighting for safety purposes.
  - Federal and state regulations require specific types of explosion proof lighting.

UBD/PWD Equipment

- Rotating/Control Heads:
  - Developed to control pressure while drilling underbalanced.
  - Accidents occur while putting too much pressure on the rotating head rubber.
  - There are different types of rotating and control head products.
  - Low pressure tests of 200 to 300 psi are required and high pressure tests are optional.
- Kelly Types:
  - Tri-Kelly.
  - Hex-Kelly.
  - Square-Kelly.

UBD/PWD Equipment

- Stripper Rubbers:
  - Used for air, gas, and water based fluid drilling.
  - For oil based drilling fluids, polyurethane stripper rubbers are available.
- Pressure Testing:
  - Testing procedures for the rotating head should follow manufacturer’s recommended procedures.
- Double Annulars:
  - Before the improvement in higher working pressure of rotating heads, double annulars were used to protect the crew.
  - Having double annulars caused substructure restrictions on many rigs.

UBD/PWD Equipment

- Special Considerations/High Angle-Horizontal and UBD/PWD Wells:
  - The entire rig crew should be familiarized with certain things by the operator’s representative before drilling the curve:
    - Must know that the well may be shut in at any time, and many times, the situation is not as severe as it looks.
    - Surface equipment is tested before drilling the curve.
      - *The crew must have confidence in the equipment, so letting them see the test results of equipment is a good idea.*
    - Must know all stations, duties, and responsibilities.
    - Must know where all emergency numbers are posted.
    - Must be prepared for dangerous situations in order to avoid panicking.
    - In most safety operations, crew assignments in horizontal wells and vertical wells are similar.

Well Kicks When the Pipe is Off Bottom

- Kicks that occur while tripping are usually due to a failure to detect a swabbing effect because the hole is not taking the proper amount of fluid.
- Once an influx in the wellbore is noticed, the well should be shut in and controlled by stripping or staging back to bottom, and pressures should be low.
- Generally, stripping back to bottom is one of the best options; however, pressures to hold versus volumes gained can be complex with well geometry and various pipe sizes.

Well Kicks When the Pipe is Off Bottom

- Hold the proper pressure.
  - Pressure to hold = Original SICP + (Pressure Gradient (psi/ft)/ Annulus Capacity (bbls/ft)) for each barrel of fluid gained as you strip back to bottom.
- Generally, once stripped back on bottom, the Driller's Method is used because the result was a swabbed kick where no additional fluid weight may be required.

Stripping

- Stripping is the adding or removing of pipe when the well is pressured without allowing vertical flow at the top of the well.

  * *Remember, if pressure is not watched carefully and adjusted according to the displacement of pipe being stripped and gas expansion, the mistake may lead to additional influx and/or extreme pressures in the well.*

- If stripping, all personnel should be briefed and familiar with their responsibilities.

Stripping

- Since stripping may lead to equipment failure, such as wearing of sealing elements, **all activities should be performed carefully.**
- A float or inside BOP in the string is required whenever stripping in or out.
- To calculate if stripping operations will exert enough downward force to push pipe into the well against pressures and preventer friction, use the following calculation:

$$\mathbf{Swt = (0.7854 \times D^2 \times P) + F}$$

Where:

Swt	=	estimated weight need to strip into hole, lbs
D	=	diameter of largest collar or tool joint in inches
P	=	annular pressure, psi
F	=	approximate pipe weight to slide through packer rubber (use a minimum of 2,000 lbs), lbs

Stripping with the Annular Preventer

- For stripping purposes, the annular preventer is much easier and less time-consuming than rams.
- There are some restrictions and special points that need to be checked prior to use of the annular preventer:
  - Consideration for stripping in the Hole with the Annular Preventer.
  - Stripping Out of the Hole with the Annular Preventer.
  - Stripping in the Hole using Pipe Rams.

Concentric Techniques

- Small tubing, snubbing and coiled tubing units are specialized units that can strip and snub into pressured wells. For our purposes, the differences are defined as:
  - Stripping – movement of pipe in or out of well against pressure when pipe weight is greater than the force to be overcome.
  - Snubbing – forcing of pipe in or out of well against pressure that is great enough to eject the pipe.

Concentric Techniques

- Seals from well pressures are provided by specialized stripper assemblies. These are usually lubricators, stripper preventers or specialized BOPs.