CDF TRAINING

WELL CONTROL TRAINING WORKBOOK

Surface Well Control | Participant Workbook

Course ______________________________

Student Name ______________________________

Date ______________________________

Instructor ______________________________

TRAIN LIKE IT MATTERS,

BECAUSE IT DOES.

Practical well control training built for the decisions crews make on the rig.

WORKBOOK OUTLINE

Well Control Training Workbook

Section 1 — Well Planning and Preparation Procedures

Section 2 — Basic Concepts

Section 3 — Causes of Kicks

Section 4 — Kick Warning Signs

Section 5 — Kick Indicators

Section 6 — Secondary Well Control

Section 7 — Kill Methods

Section 8 — Calculations

Section 9 — Well Control Equipment

Section 10 — Additional Methods and Techniques

Section 11 — Managing Well Control Operations

Supplementary Review

- Knowledge & Concepts
- Scenarios & Application
- Calculations
- Answer Key

1.1 – Introduction and Definitions

In every drilling operation, control begins long before the first joint of pipe goes in the hole. Well planning and preparation define how the team will keep formation fluids contained and the well stable from spud to completion.

We call this *primary well control* — using mud hydrostatic pressure to balance formation pressure.

When that balance fails, *secondary well control* — the Blowout Preventer (BOP) system —

acts as the mechanical backup to seal the well.

Key Terms

- Kick – The entry of formation fluid into the wellbore when mud pressure is too low.
- Blowout – An uncontrolled low of formation fuids to surface.
- Primary Control – Hydrostatic pressure created by the mud column.
- Secondary Control – The use of BOPs and related equipment to seal the well.

Example

While drilling ahead at 10 000 ft, a gas zone is encountered. The mud weight was reduced earlier to improve rate of penetration. A rise in return low and pit gain shows a kick is starting. The driller shuts in the well using the BOP — secondary control now protects the rig.

Reflection

When you think of *control*, which comes first on your rig — equipment or awareness?

Insight:

Knowledge and attention are the real first barriers; the tools only work when the crew reacts in time.

1.2 – Kick Indicators

A kick rarely happens without warning. The well communicates through subtle changes in low, pit level, and pressure. Reading those changes early keeps the event small and controllable.

Primary Surface Indicators

- **Increase in Return Flow** – Flow rate out is greater than fow rate in.
- Pit Gain – Active pit volume rises without pumping additional mud.
- **Flow with Pumps Of** – Mud continues to low when circulation stops.
- **Trip Tank Changes** – Unexpected gain or loss during tripping.
- **Gas-Cut Mud / Flowing Mud / Pump Pressure Changes** – Additional confirmation that formation fluid is entering.

Example

During a connection, the driller shuts down pumps but sees continued low at the lowline. Pit volume increases by two barrels. The crew shuts in the well immediately — textbook early detection.

Reflection

Which indicator do you trust most when deciding to shut in—the pit gauge or the low line?

Insight:

Kicks don't surprise an alert crew. Small changes seen early prevent big problems later.

1.3 – Primary and Secondary Well Control

Every well has two defenses. The first is pressure; the second is equipment.

Primary Control

Mud hydrostatic pressure must always be slightly greater than formation pressure. This balance prevents influx. Maintaining mud weight, monitoring pits, and keeping the well full preserve this line of defense.

Secondary Control

When primary control is lost, the BOP system provides the mechanical seal. It closes around the drill string or across the open hole, stopping low so pressure can be managed and the well killed safely.

Example

After detecting a kick, the driller raises the bit of bottom, stops rotation, and closes the annular preventer. Pressures stabilize, showing the BOP is holding. The well is now secure for kill-procedure planning.

Reflection

How confident are you in the response time between recognizing a kick and closing the BOP?

Insight:

Two barriers — mud and BOPs — work only when both are maintained. Neglect either, and the well decides the outcome.

1.4 – Workover and Completion Program

Every well eventually needs maintenance or modification.

A workover restores production in an existing well; completion prepares a newly drilled well for production.

Both operations disturb the well's pressure balance, so barrier control and fluid management are critical.

Reasons for Workover

- Repair mechanical damage or leaks.
- Control unwanted water or gas production.
- Stimulate a formation to increase flow.
- Re-complete in a new zone or reservoir

Reasons for Completion

- Convert a drilled well into a producing one.
- Install tubing, packers, and safety valves.
- Isolate zones with cement or mechanical barriers
- Prepare for long-term pressure monitoring and flow control

Example

A producing well begins to pump sand and loses pressure. A workover is planned to install a sand-control screen. If fluid weight isn't properly maintained during the pull, gas can migrate up the tubing and reach surface — an avoidable hazard with correct barrier planning.

Reflection

When a well is opened for workover, which barrier gives you confidence that control will be maintained?

Insight:

Production goals mean nothing without pressure control. Treat every workover like a new well—plan the barriers first.

1.5 – Drilling Fluid Program

Mud is the heart of well control. It provides hydrostatic pressure, removes cuttings, cools the bit, and stabilizes the hole.

Without the right mud properties, no amount of equipment can keep a well safe.

Key Objectives

- Maintain sufficient density to overbalance formation pressure.
- Keep the well full of correctly weighted fluid at all times.
- Continuously monitor pit volumes and trip tank levels
- Adjust mud weight as depth and formation pressure change.

Example

While drilling at 10 000 ft, mud weight drops from 10.0 ppg to 9.7 ppg after dilution. A gas kick begins, indicated by rising pits and increased low. The mud engineer restores density, the crew circulates heavier mud, and balance is regained.

Reflection

Do you check mud weight because it's required—or because you know what's at stake if you don't?

Insight:

Mud is more than fluid—it's your first barrier. If you respect it, it will protect you.

1.6 – Barrier Management: Two-Barrier Rule

Every operation on a live well must maintain at least **two independent tested barriers**

between the reservoir and the surface.

If one fails, work stops until it's restored or replaced.

Acceptable Barriers

- A verified fluid column of known density providing hydrostatic pressure.
- BOPs or remotely operated valves, pressure-tested regularly
- A properly placed cement plug (; 100 ft) that has been tagged and pressure-tested.
- A mechanical plug, packer, or valve that seals low paths and is verified for pressure.
  integrity

Application

During completion work, the production packer and a column of weighted brine may serve as the two barriers. If either is compromised, the well must be secured before continuing.

Example

While running tubing, pressure tests reveal the packer seal is leaking. Operations stop, fluid weight is increased, and the seal is re-tested before proceeding — textbook compliance with the two-barrier rule.

Reflection

Which barriers protect you right now—and how do you know they're holding?

Insight:

Barriers are promises, not paperwork. They only matter if they're tested, verified, and respected every time.

SECTION 2 – BASIC CONCEPTS

2.1 – Definitions

Well control begins with understanding the basic pressures that exist in every well. Pressure is the force exerted by a fluid per unit area, and in drilling, every type of fluid — mud, oil, gas, or water — exerts its own pressure.

Knowing how they interact determines whether the well stays stable or begins to flow.

Key Definitions

- **Pressure:** The force exerted by a fluid, measured in pounds per square inch (psi).
- **Hydrostatic Pressure:** Pressure created by the weight of the drilling fluid column.
- **Formation Pressure:** Pressure of fluids trapped within the rock layers.
- **Bottom Hole Pressure (BHP):** The total pressure acting at the bottom of the well.
- **Fracture Pressure:** The point where the formation breaks and accepts fluid.
- **Primary Well Control:** Balance maintained by mud hydrostatic pressure.
- **Secondary Well Control:** Use of BOPs and mechanical barriers to stop flow.

Example

While drilling at 10,000 ft, the mud column exerts 5,200 psi hydrostatic pressure. If the formation pressure is also 5,200 psi, the well is balanced.

Any drop in mud density or height reduces pressure — and may allow formation fluids to enter.

Reflection

Can you explain the difference between hydrostatic pressure and formation pressure in one sentence?

Insight:

You can’t control what you don’t understand — pressure knowledge is pressure control.

2.2 – Hydrostatic Pressure

Hydrostatic pressure is the foundation of well control.

It’s the pressure exerted by the column of drilling fluid in the wellbore, and it’s calculated using the formula:

$$P = 0.052 \times MW \times TVD$$

Where:

- **P** = Hydrostatic Pressure (psi)
- **MW** = Mud Weight (ppg)
- **TVD** = True Vertical Depth (ft)

Key Points

- Heavier mud = higher hydrostatic pressure.
- Pressure increases with depth.

- Gas-cut or diluted mud lowers hydrostatic pressure.

Example

At 10,000 ft using 10 ppg mud:

0.052 × 10 × 10,000 = **5,200 psi** hydrostatic pressure.

If the formation pressure is 5,000 psi, the well is overbalanced — safe and stable.

Reflection

If mud weight drops 0.2 ppg, how many psi are lost at 10,000 ft?

Insight:

Every tenth of a pound per gallon counts — small changes at surface equal big difference at bottom.

2.3 – Drilling Fluid

Drilling fluid (mud) is the **first line of defense** in maintaining well control.

Its job goes beyond carrying cuttings — it must keep the well balanced, cool the bit, and stabilize the hole.

Functions of Drilling Fluid

- Provides hydrostatic pressure to prevent kicks.
- Carries cuttings to surface.
- Cools and lubricates the drill bit and string.
- Forms a mud cake to stabilize the wellbore walls.
- Transmits hydraulic energy for efficient drilling.

Example

If the mud becomes too thin, its density drops.

A 9.5 ppg mud may fall to 9.2 ppg, reducing hydrostatic pressure enough to allow gas to enter the wellbore.

Reflection

When mud returns look "lighter" than expected, what's your next move?

Insight:

Mud doesn't just make a hole, it makes control.

2.4 – Geology

Geology determines where formation pressures come from.

As sediments compress over millions of years, fluids trapped inside porous rocks build pressure beneath impermeable layers such as shale or salt.

When drilling penetrates those seals, the trapped fluids seek a lower pressure path — the wellbore.

Pressure Factors in Geology

- **Depth:** Deeper formations = higher pressure.
- **Rock Type:** Sandstone stores fluids; shale seals them.
- **Fluid Type:** Gas exerts more pressure per volume than oil or water.
- **Impermeable Traps:** Layers that prevent fluids from escaping, creating abnormal pressure.

Example

A gas sand trapped beneath shale holds abnormal pressure.

When drilled with light mud, the gas expands and pushes into the wellbore — creating a kick.

Reflection

What type of formation usually traps pressure — permeable or impermeable?

Insight:
The rock always wins unless you understand its story.

2.5 – Concept of Balance

A stable well is a **balanced well**.

This balance depends on keeping mud pressure equal to formation pressure. If mud weight is too low, the well flows; if too high, it fractures.

Condition	Description	Result
Underbalanced	Mud Pressure < Formation Pressure	Kick / Influx
Balanced	Mud Pressure = Formation Pressure	Stable Well
Overbalanced	Mud Pressure > Formation Pressure	Lost Returns / Fracture

Example

While drilling with 9.6 ppg mud, the well starts to flow. A formation test shows it needed 9.8 ppg for balance. Adding barite restores control and stops flow.

Reflection

Do you think it's safer to drill slightly heavy or slightly light?

Insight:
Control isn't about being stronger — it's about being equal.

2.6 – Formation Fracture

Fracture pressure is the **maximum pressure** a formation can handle before breaking. When exceeded, the formation fractures, and mud is lost — eliminating hydrostatic control.

Key Concepts

- Each formation has its own fracture gradient (psi/ft).
- Fracture gradient increases with depth.
- Safe drilling stays between formation and fracture pressures.

Example

At 10,000 ft, a formation has a fracture gradient of 0.8 psi/ft.

$0.8 \times 10{,}000 = 8{,}000$ psi fracture pressure.

If mud weight or surface pressure pushes total BHP above that, mud is lost into the formation.

Reflection

Do you know your current fracture gradient and safety margin on your well?

Insight:
Too much control can be just as dangerous as too little.

2.7 – Principle of the U-Tube

The **U-tube principle** explains how fluid levels and pressures equalize in the wellbore and annulus.

Think of the drill pipe and annulus as two connected columns of fluid — like a U-shaped tube.

Key Points

- When both sides contain the same fluid, the levels stay equal.
- If one side becomes lighter (gas influx), fluid rises on that side.
- The system always seeks equilibrium between both columns.

Example

If gas enters the annulus, it lightens the column, lowering pressure on that side. The heavier mud in the drill pipe pushes fluid upward — the well begins to flow.

Reflection

When pumps stop, what happens to bottom-hole pressure if gas is present in the annulus?

Insight:
A well is a U-tube that never lies — unequal weight means unequal control.

2.8 – Frictional Pressure Loss

When mud circulates, friction between the fluid and wellbore adds **frictional pressure** (or annular pressure loss).

This added pressure raises bottom-hole pressure during circulation.

$$BHP = \text{Hydrostatic Pressure} + \text{Friction Pressure (APL)}$$

When pumps stop, friction disappears — pressure at the bottom drops. If the well was slightly overbalanced, that drop can allow flow.

Factors That Increase Friction Pressure

- Higher flow rate
- Increased mud viscosity
- Smaller annular clearance
- Rough or irregular wellbore

Example

A well circulating 10 ppg mud has 400 psi annular pressure loss. While pumps run, BHP = Hydrostatic + 400 psi.

When pumps stop, 400 psi disappears — pressure drops, and the well can kick.

Reflection

Do you know how much friction pressure your system adds while circulating?

Insight:
Every turn of the pump changes the math — friction helps you or hurts you depending on control.

2.9 – Bottom Hole Pressure and Equivalent Mud Weight

Bottom Hole Pressure (BHP) is the **total pressure** acting at the bottom of the well. It includes both hydrostatic pressure and the pressure from circulation (friction).

$$BHP = (0.052 \times MW \times TVD) + \text{Friction Pressure}$$

When circulating, the BHP increases slightly — this is expressed as **Equivalent Circulating Density (ECD):**

$$ECD = MW + \frac{\text{Friction Pressure}}{0.052 \times TVD}$$

Example

At 10,000 ft with 10 ppg mud and 400 psi friction pressure: ECD = 10 + (400 ÷ (0.052 × 10,000)) = **10.77 ppg**

That means the formation "feels" a 10.77 ppg mud while circulating.

Reflection

Do you account for ECD when adjusting mud weight, or only static pressure?

Insight:
Circulation adds invisible weight — ignoring it can lead to lost returns or a kick.

SECTION 3 – CAUSES OF KICKS

Introduction

A **kick** occurs when formation pressure becomes greater than the hydrostatic pressure of the drilling fluid in the wellbore.

When that balance fails, formation fluids enter the well — and the longer it goes unnoticed, the harder it becomes to control.

Kicks can happen for two main reasons:

1. **A reduction in mud hydrostatic pressure.**
2. **An increase in formation fluid pressure.**

Understanding how each occurs allows crews to prevent them before they start.

3.1 – Reduction in Mud Hydrostatic Pressure

The most common cause of a kick is a **reduction in mud hydrostatic pressure**.

When the mud column becomes lighter or shorter, the well becomes underbalanced and allows formation fluids to enter.

Common Causes

1. Drop in Mud Level

- **Failure to fill hole:** When pulling pipe, the volume of steel removed must be replaced with mud. If not filled, the fluid column shortens and hydrostatic pressure drops.
- **Losses to the formation:** Mud flowing into a thief zone reduces active volume and pressure.
- **Equipment leaks:** Leaks in surface lines, pump suction, or standpipe lower the effective mud column.

Example

During a trip, the driller forgets to fill the hole every five stands. The mud level drops, hydrostatic pressure falls, and gas enters from the formation — a classic swab-induced kick.

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2. Drop in Mud Density

- **Dilution:** Adding water or base fluid without weighting material reduces mud density.
- **Barite Settling:** Improper circulation allows weighting material to settle out, reducing bottom-hole pressure.
- **Light Pills or Displacement:** Pumping lighter fluids (like spacer or cement pre-flush) can cause temporary underbalance.
- **Gas Cut Mud:** Entrained gas reduces effective density, lowering hydrostatic pressure.

Example

After mixing a slug, circulation was delayed for hours. Barite settled, and the mud in the hole was 0.3 ppg lighter. When drilling resumed, the well flowed.

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3. Swabbing

Swabbing happens when pulling pipe too fast, creating suction that draws formation fluids into the wellbore. It's most common in tight or plastic formations.

Prevention Tips

- Pull pipe at steady, moderate speeds.
- Use proper mud properties for hole cleaning.
- Monitor trip tank volumes carefully.

Example

A driller trips 10 stands without watching the trip tank. The well gains two barrels — unnoticed until flow appears at the flowline.

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4. Other Causes

- **Gas-Cut Mud:** Gas entering and expanding in mud lowers density.
- **Mud Loss:** Partial or complete loss of returns reduces effective mud height.
- **Cementing:** Displacement with light fluids can temporarily reduce hydrostatic head.

Trip Margin

Trip margin is the **extra mud weight** added before pulling out of hole to prevent swabbing or underbalance.

Maintaining a small safety margin ensures hydrostatic pressure remains greater than formation pressure, even if mud is displaced by steel removal.

Reflection

How often do you check mud weight before tripping out of hole — every time, or only when problems occur?

Insight:

Kicks don't happen all at once — they start with small losses, missed fills, or light mud. Control the details, and you control the well.

3.2 – Increase in Formation Fluid Pressure

Sometimes, the formation pressure itself increases unexpectedly.

This can be caused by trapped fluids, geological movement, or pressure communication from nearby formations.

Common Causes

- **Trapped Fluids:** Shale, salt, or anhydrite seal porous zones, trapping fluids that cannot escape.
- **Artesian Effect:** Water-bearing zones higher than the rig elevation can create natural flow.
- **Faults or Folds:** Geologic movement can redirect pressure or connect isolated reservoirs.
- **Salt Domes:** Pressure increases as formations are displaced upward by rising salt.
- **Gas-Cap Expansion:** Gas expands into surrounding formations, increasing pressure near the wellbore.
- **Leaking Casing Shoes:** Fluid communication from higher-pressure zones behind casing.

Example

While drilling near a salt dome, the bit encounters a permeable sand layer. Trapped gas expands against the wellbore, creating higher-than-expected pressure and causing a kick.

Reflection

Do you rely on mud logs and offset data to predict pressure zones — or on what you “feel” from the brake handle?

Insight:

The earth shifts, breathes, and builds pressure where you least expect it. Trust data, not luck.

3.3 – Intentional Kicks

Not all kicks are accidental.

Sometimes, crews intentionally allow the well to flow under controlled conditions for training, well testing, or data collection.

These are called **intentional or induced kicks. When**

Intentional Kicks Are Used

- Formation testing operations.
- Well control training (under supervision).
- Data collection for reservoir pressure analysis.

During these operations, strict procedures, equipment, and supervision are required to maintain safety and prevent escalation.

Example

During a drillstem test (DST), a formation is intentionally allowed to flow into the drill string. Once pressure data is collected, the BOP is used to shut in the well and restore balance.

Reflection

Would you recognize the difference between a planned flow and an accidental kick on your rig?

Insight:

Even a planned kick can turn unplanned in seconds — control must be deliberate, not assumed.

3.4 – Shallow Gas

Shallow gas is a near-surface zone with trapped gas under pressure.

It can occur at depths less than 1,000 ft and presents unique challenges because there’s little mud column to contain it.

Key Hazards

- High flow rates with minimal warning.
- Rapid gas expansion due to low overburden pressure.
- Limited response time for shut-in or choke control.

Detection and Prevention

- Review seismic or offset well data before spud.
- Use controlled drilling and slow ROP through known shallow zones.
- Maintain mud returns and monitor pit volume closely during surface hole drilling.

Example

While drilling surface hole at 600 ft, gas cut mud appears suddenly. Within minutes, the well begins to flow — a shallow gas influx. The crew closes the diverter and directs flow to the flare line to maintain safety.

Reflection

Do you treat surface holes as low-risk — or recognize that shallow gas can be the most dangerous zone in a well?

Insight:

Depth doesn't define danger — shallow kicks move fastest and give the least time to react.

Insight: **nal Thought):**

Most kicks don't come from bad luck — they come from missed warning signs. The crew that watches the small things never has to fight the big ones.

SECTION 4 – KICK WARNING SIGNS

Introduction

Kicks rarely happen without warning.

The well always gives signs — through its drilling behavior, mud properties, and pressure readings.

The crew's job is to **see the change**, **recognize the pattern**, and **act fast** before the well flows.

Every well control event can be traced back to missed or ignored warning signs. Understanding them — and reacting early — is the difference between control and chaos.

4.1 – Rate of Penetration (ROP) Changes

When formation pressure increases, the **rate of penetration (ROP)** often increases suddenly.

This happens because the differential pressure holding the formation back decreases — the bit cuts faster and the rock breaks more easily.

Common Causes of Abnormal ROP Increases

- Drilling into a **high-pressure zone** (less overbalance).
- Encountering **soft or gas-bearing formations.**
- **Bit wear or weight-on-bit changes** masking the true cause.

Field Example

While drilling, ROP jumps from 20 ft/hr to 45 ft/hr with no change in weight or RPM. Mud returns show small gas bubbles. Within minutes, pits rise one barrel — the well is starting to flow.

Recognition Tips

- Compare ROP changes with lag time (mud circulation delay).
- Watch for rising gas or pit volume soon after.
- Use consistent drilling parameters to spot true formation changes.

Reflection

Do you treat sudden ROP increases as good news — or as a reason to check the pits?

Insight:

Not every fast hole is good hole — pressure makes rock soft before it makes trouble.

4.2 – Hole Condition

A well that's "talking back" often shows changes in hole condition before it kicks. These are the subtle mechanical signs that pressure balance is shifting.

Warning Signs in Hole Condition

- **Tight hole or overpull:** Formation swelling or pressure pushing in.
- **Cutting shape or size changes:** Larger, flatter cuttings mean pressure is closer to balance.
- **Caving's or sloughing:** Overbalanced conditions causing hole enlargement.
- **Pump pressure fluctuations:** Formation fluids entering the annulus or changes in mud weight.

Example

While tripping out, the driller notices increasing drag and longer fill-up times.

Trip tank shows 3 barrels unaccounted for — formation fluids entering while pulling pipe.

Prevention

- Monitor trip tank closely.
- Keep a consistent tripping speed.
- Stop and circulate if volumes don't match expectations.

Reflection

When your pipe pulls harder than usual, do you stop to ask *why* — or pull faster to get it free?

Insight:

A tight hole can mean the formation's fighting back — and it never fights fair.

4.3 – Data from Mud

Mud properties often reveal early warning signs of pressure changes before they appear on gauges.

The mud logger's readings can confirm what the well is saying.

Mud-Related Warning Signs

- **Gas-Cut Mud:** Expanding gas reduces mud weight and density.
- **Mud Weight Decrease:** Dilution or gas-cutting lowers hydrostatic pressure.
- **Chloride Content Increase:** Saltwater intrusion from formation fluids.
- **Viscosity or Gel Strength Changes:** Indicate gas or contaminants entering the system.

Example

Mud logger notes a decrease in mud weight from 9.8 to 9.5 ppg after a connection. Chlorides and gas readings both increase — signs of formation fluids entering the well.

Preventive Steps

- Check mud weight regularly at both pits and flowline.
- Maintain mud properties according to the fluid program.
- Communicate all mud changes to the driller immediately.

Reflection

Do you wait for the mud logger's report — or look at the pit screens yourself?

Insight:

The mud tells the truth before the pressure does — if you're listening.

4.4 – Data from Other Sources

Not all kick indicators come from mud or hole behavior.

Instrument readings, sensors, and flow-line data give measurable confirmation of formation influx.

Surface Data Warning Signs

- **Pit Volume Increase:** The most reliable surface indicator of a kick.
- **Flow Rate Increase:** Flow out greater than flow in at steady pump speed.
- **Flow with Pumps Of:** The well continues to flow after circulation stops.
- **Standpipe or Casing Pressure Increase:** Formation fluids entering the annulus increase pressure.
- **Trip Tank Anomalies:** Unexpected gain or loss during trips.

Example

After stopping pumps for a connection, flow continues at the flow line. Pit volume rises by two barrels — clear evidence of influx.

The driller shuts in the well immediately.

Reflection

When pits rise or flow continues, what's your first move — observe or act?

Insight:

Every barrel gained is a barrel you'll have to control later — act early, not after.

4.5 – Gas, Cuttings, and Connection Indicators

Gas and cuttings behavior can give away pressure changes long before a kick occurs.

Indicators to Watch

- **Background Gas:** Gradual increase means rising formation pressure.
- **Trip Gas:** Gas released when pulling out of hole — possible underbalance.
- **Connection Gas:** Gas bubbles appearing after pumps stop — early influx indicator.
- **Cuttings Shape:** Flattened, concave, or shiny cuttings often signal higher pore pressure.

Example

After each connection, gas readings spike. Cuttings become concave and lighter in color. Mud weight checks show a 0.2 ppg drop — warning that the well is near balance and could flow.

Prevention

- Track background gas trends, not just spikes.
- Recheck mud weight frequently.
- Slow circulation to confirm if changes are real or transient.

Reflection

Do you look at gas readings as routine data — or as a direct conversation with the well?

Insight:

Gas always arrives before trouble — and it never knocks twice.

4.6 – Review and Exercises

Quick Review

- **ROP, hole condition, and mud properties** give early warnings of pressure imbalance.
- **Pit gain, flow increase, and continued flow** are clear surface indicators of influx.
- **Gas readings** are your first sign that formation fluids are entering the system.
- Reacting early prevents escalation — hesitation makes a small problem a big one.

Exercises

1. List three early kick warning signs seen while drilling.
2. What does a sudden ROP increase often indicate?
3. Name two mud property changes that can signal an influx.
4. Why is pit gain considered the most reliable surface indicator?
5. How can connection gas differ from trip gas?
6. What's the safest first response when a kick is suspected?

Insight: nt:

A kick never happens without an invitation.

Every change — in rate, return, or reading — is the well asking, "Are you watching me?"

SECTION 5 – KICK INDICATORS

5.1 – Introduction

Kick indicators are the **visible surface signs** that a well is no longer balanced.

If these signs are recognized and acted upon immediately, the influx can be contained and killed safely.

If ignored, the well can load with formation fluids and quickly escalate into a blowout.

Primary Surface Indicators

- Excess flow from the well while tripping
- Increase in return flow rate while pumping.
- Pit gain
- Drop in pump pressure with rising pump SPM.
- Flow from the well with pumps of

Example

While drilling, the driller notices the flow paddle swinging wider and pit volume rising. Pumps are shut down and the well is found to be flowing — a confirmed kick.

Reflection

When was the last time you personally verified that all flow alarms were functional?

Insight:

A kick announces itself — only the inattentive crew fails to hear it.

5.2 – Flow Rate

A **flow check** determines if the well is static or flowing.

It's performed by stopping operations and observing the fluid level in the well or trip tank long enough for equilibrium to stabilize.

How to Flow Check

1. Stop drilling or tripping activity.
2. Close the flow line and line up the trip tank.
3. Observe fluid level for at least 15 minutes.
4. If level rises, the well is flowing — **shut in immediately. Tripping Out:** Failure t

fill the hole equals loss of hydrostatic head.

Tripping In: Flow should stop once the stand is set. Continuous flow indicates a kick. **Drilling:** Flow rate in = flow rate out. Any increase means influx; any decrease means losses.

Reflection

Do you rely on automatic flow alarms — or do you confirm them with your own eyes?

Insight:
Flow rate tells the truth faster than any gauge — believe what the flow line shows.

5.3 – Pit Gain

When formation fluid enters the wellbore, it displaces mud and causes a **pit gain**.

Pit gain volume equals influx volume; it's one of the most dependable surface indicators.

Key Practices

- Monitor active system constantly.
- Use the smallest possible pit area for better resolution.
- Stop drilling and flow check any unaccounted-for gain or loss.
- Set pit alarms (±5 bbls typical).
- Record all mud transfers to avoid false readings.

Example

During drilling, pit volume rises 8 bbls without any mud transfer. Pumps of → flow continues → well shut in → kick confirmed.

Reflection

Do your pit records tell a clear story—or a confusing one?

Insight:
Every unexpected barrel in the pit belongs to the formation. Find out why now, not later.

5.4 – Pressure vs SPM

When a kick starts, formation fluids lighten the annulus and reduce friction losses. Pump pressure drops while pump speed (SPM) rises slightly.

Combined Indicator

- Decreased pump pressure
- Increased SPM
- Often appears together with pit gain or flow increase.

Action

If you see pressure fall and SPM rise — stop and perform a flow check. If in doubt → shut in.

Reflection

How quickly could you recognize this pattern at your console?

Insight:
Falling pump pressure and rising SPM mean the well is helping you — and that's never good.

5.5 – Flow with Pumps Of

Flow continuing after pumps stop is the **first solid proof** of an active kick. Once confirmed, act immediately — time wasted increases danger.

Procedure

1. Shut down pumps.

2. Observe flow line or trip tank for movement.

3. If level rises or flow continues → **shut in the well. Example**

Pumps stopped for a connection; flow paddle keeps moving, trip tank gains 1 bbl. The driller closes the BOP — kick stopped small.

Reflection

How many seconds pass between seeing continued flow and starting your shut-in?

Insight:

When the pumps are of and the well still flows, it's no longer a question — it's a kick.

5.6 – False Indicators

Not every change means a kick. Some surface events can mimic influx symptoms.

Common False Indicators

- **Flow changes:** pump speed changes, U-tubing from heavier mud, ballooning shales.
- **Pit gains:** mud transfers, adding water, leaks into active system, or bypassing equipment.

If uncertain, always treat it as a kick until proven otherwise.

Reflection

Do you stop to prove an indicator false — or assume it is?

Insight:

It's safer to shut in on a false alarm than to explain why you didn't.

5.7 – Permeability

Permeability is the ability of a formation to let fluids move through its pore spaces. High-permeability rocks allow faster influx; low-permeability rocks feed the well slowly.

Concept

- High permeability → fast, high-rate kick.
- Low permeability → slow kick, same pressure eventually.
- Shales = low perm (can mask underbalance).
- Sands = high perm (drill fast → kick fast).

Example

After a drilling break in a sandstone, flow wasn't checked for 20 ft. The influx entered rapidly due to high permeability — a larger kick than expected.

Reflection

After a drilling break, how soon should you flow check before drilling deeper?

Insight:

High permeability turns seconds into barrels — check flow early, keep kicks small.

5.8 – What If the Well Is Flowing?

Once the well is flowing, **secondary control** begins.

That means the formation has entered the wellbore, and it's time to shut in and regain control.

Steps

1. **Close the BOP** — seal the well.

2. **Record pressures** — SIDPP and SICP.
3. **Prepare Kill Plan** — restore hydrostatic balance safely.

Example

The driller detects continued flow, closes the BOP, records 350 psi SIDPP and 500 psi SICP, and begins shut-in reporting. Kick contained, no loss of control.

Reflection

Is every member of your crew confident in the exact shut-in steps for your rig?

Insight:

Shut in fast — you can always open up later, but you can't un-blow a well.

Section 6 – Secondary Well Control

6.1 – Reasons for Shut-In

When abnormal pressure or influx is detected, the well must be shut in immediately to stop formation fluids from entering the wellbore. The decision to shut in is based on warning signs that something below surface is no longer balanced.

Common Reasons:

- Unexpected increase in pit gain or mud volume
- Sudden increase in pump pressure or low rate
- Gas cut mud returning to the surface.
- Drilling break or change in penetration rate.
- Decrease in mud weight or loss of hydrostatic balance.

Key Point:

A shut-in protects the well and crew from a kick escalating into a blowout.

Example:

While drilling at 9,000 ft, the driller notices mud pits rising by 10 bbl within minutes. He stops the pump and closes the annular preventer to isolate the well — preventing gas migration up the wellbore.

6.2 – Shut-In Methods

Once the need to shut in is confirmed, one of two standard methods is used — Hard Shut-In or Soft Shut-In.

Both aim to trap the influx safely and establish control, but differ in pressure management.

Hard Shut-In Method:

- Drill pipe valve and annular preventer closed in quick sequence.
- No fluid circulation during closing
- Fast isolation of the well but higher initial pressure spikes

Soft Shut-In Method:

- Flow checked with the choke open initially.
- Choke gradually closed while preventer closes.
- Slower pressure build but reduces shock load on BOP and lines

When to Use:

- Hard shut-in is preferred for surface stacks with strong equipment and trained crew.
- Soft shut-in is common for subsea or sensitive equipment to reduce shock pressures.

Example:

In land operations, a driller detects low after a connection. He performs a hard shut-in by closing the annular and the choke quickly — trapping the kick safely.

6.3 – Shut-In While Tripping

When tripping, the drill string is not connected to the pumps. A kick can occur if swabbing or mud displacement reduces hydrostatic pressure. If low is seen, the well must be shut in immediately using the appropriate valve.

Shut-In Steps While Tripping:

1. Stop running pipe immediately.
2. Install a Full Opening Safety Valve (FOSV) or TIW valve on the string.
3. Close the annular preventer to seal the well.
4. Record pressures once the well is secured.

Key Notes:

- Always have the safety valve readily available on the floor.
- Pressure buildup can occur rapidly since the string is static.
- Proper communication between floor crew and driller is critical to avoid delays.

Example:

While pulling out of hole at 7,500 ft, low is noticed from the bell nipple. The crew installs the FOSV, closes the annular preventer, and records shut-in pressures before notifying the company man.

Insight:

Speed and accuracy save the well. A 30-second delay can allow gas to migrate hundreds of feet up the wellbore.

6.4 – Advantages of Shut-In Methods

Each shut-in method offers benefits depending on equipment, crew readiness, and rig type.

Choosing the correct approach prevents unnecessary stress on the well or surface equipment.

Hard Shut-In Advantages:

- Fast isolation of the well
- Reduces risk of continued influx
- Simple procedure for land rigs

Soft Shut-In Advantages:

- Reduces surface pressure spikes
- Protects sensitive BOP and choke lines
- Allows better control in subsea systems

Key Point:

Both methods work — the goal is safe isolation, not speed.

Example:

A rig using a soft shut-in method experienced less wear on choke lines and seals over time

— saving maintenance costs.

Insight:

No matter which method is used, consistent crew practice and communication are the deciding factors for success.

6.5 – Special Situations

Special conditions can occur where standard shut-in steps may not apply exactly. These demand careful adjustments while maintaining control.

Common Situations:

- Stripping operations: Pipe is moved through closed preventers while controlling pressure.

- Swabbing while tripping: Unintentional lowering of bottom-hole pressure draws in formation fluids.
- Partial shut-in: Used if pipe is stuck or equipment limitations exist.
- Pump or choke failure: Requires manual backup procedures.

Example:

During stripping operations, pressure is monitored constantly to avoid over pressuring the casing while maintaining a steady low through the choke.

Insight:
Unusual situations test judgment — understanding *why* we control low is more important than memorizing a checklist.

6.6 – Diverting

When a kick cannot be shut in safely — such as during shallow-gas drilling or conductor-hole operations — the low must be diverted away from the rig.

Diverting is not a kill operation; it's a protection operation. Key Points:

- Used when shutting in could rupture weak formations or surface casing.
- Flow is redirected through a diverter line to a safe discharge area.
- Diverter valves must be lined up correctly before spudding.
- Always maintain full returns to watch for early kick indications.

Example:

While drilling 150 ft of surface hole, gas enters the well. The driller opens the diverter and directs low through the fare line, protecting surface equipment.

Insight:
Diverting keeps the rig safe — but once you divert, you've lost control of the well. It's a last-resort action, not a routine one.

6.7 – Interpretation of Data

Understanding what surface data tells you after shut-in determines how the well will be killed.

Data must be accurate, consistent, and correctly interpreted.

Important Data Points:

- SIDPP (Shut-In Drill Pipe Pressure): Pressure on the formation through the drill string.
- SICP (Shut-In Casing Pressure): Pressure on the annulus side.
- Pit gain: Amount of influx in barrels.
- Flow rate and time: Help estimate kick volume and formation pressure.

Example:

If SIDPP = 400 psi and mud weight = 10 ppg, the formation pressure is higher than hydrostatic by 400 psi, guiding how much heavier kill mud must be.

Insight:
Numbers tell the story. If you can't explain your pressures, you don't yet understand your well.

6.8 – Float in String

A f**oat** (non-return valve) in the drill string prevents backflow into the string. It's a safety device — but can also block pressure readings during a kick.

Key Points:

- Installed in the f**oat sub** near the bit.
- Prevents cuttings or gas from lowing up the drill string.
- During a kick, it stops mud or pressure from reaching the pumps.
- If a float is installed, you must open or bypass it to read SIDPP.

Example:

While circulating, the crew sees no low at the standpipe but pressure builds in the annulus — a float in the string is isolating the drill pipe from the kick.

Insight:

Floats protect the mud pumps but can hide kick pressures. Know when it's helping — and when it's hiding data.

6.9 – Pit Gain Considerations

Pit gain is one of the first and most reliable signs of a kick.

Monitoring mud volume changes provides early warning of formation influx.

Key Points:

- 1 bbl gain = influx entered the wellbore.
- Pit levels must be logged every connection.
- Large or rapid pit gains mean a significant kick.
- Small but consistent pit gains indicate a slow influx or gas expansion.

Example:

During a trip, the driller notices a 3-bbl pit gain over five minutes. The pumps are stopped, and the well is shut in immediately — confirming an influx.

Insight:

The pit tank is your first indicator. If it moves without reason, the formation is talking to you.

6.10 – Mud Considerations

Mud properties directly affect well-control ability.

Maintaining the correct density, viscosity, and gel strength ensures hydrostatic pressure remains higher than formation pressure.

Critical Factors:

- Mud weight: Controls formation pressure.
- Gas cut mud: Lowers density — must be circulated out.
- Solids control: Prevents thick, high-pressure losses.
- **Temperature effect:** Heat thins mud and lowers hydrostatic head.

Example:

At 10,000 ft, mud weight is 11.8 ppg. After gas cutting, it drops to 11.0 ppg — losing 400 psi of hydrostatic pressure and risking a kick.

Insight:

Mud is your first line of defense. It's cheaper to keep it right than to fix a blowout.

6.11 – Gas Migration

When gas enters a shut-in well, it rises through the mud column and expands as pressure decreases.

This can increase surface pressure even though the well is closed.

Key Points:

- Caused by gas moving upward through mud after shut-in.
- Expansion follows **Boyle's Law (P1V1 = P2V2)** — as pressure drops, gas volume increases.
- Gas migration can raise casing pressure over time.
- Controlled by **bleeding of gas** carefully through the choke.

Example:

After shutting in overnight, casing pressure rises from 400 psi to 600 psi. The choke operator bleeds of 20 psi at a time until pressure stabilizes.

Insight:

Even a closed well isn't resting — gas moves. Monitor pressures until the kill begins.

SECTION 7 – KILL METHODS

7.1 Objectives of the Kill Operation

What it is:

A kill operation is performed to restore *primary well control* by removing influx and replacing the existing mud with heavier “kill mud.”

Why it matters:

When hydrostatic pressure in the well drops below formation pressure, formation fluids enter the wellbore (a “kick”). Killing the well restores control and prevents blowouts.

Example:

If a driller detects a kick due to a 10 ppg mud weight being too light, a kill mud (e.g., 11.0 ppg) is circulated to regain balance.

Insight :

Killing the well = regaining control. The goal is always to restore hydrostatic pressure balance.

7.2 Principles of Kill Methods

What it is:

All kill methods aim to maintain **constant bottom hole pressure (BHP)** — high enough to stop flow in but low enough to avoid fracturing the formation.

Why it matters:

Too little pressure = more influx.

Too much pressure = lost circulation.

Core Principle:

Maintain BHP between formation and fracture pressure. Two Constant BHP Methods:

1. **Driller’s Method** – Two circulations (clean influx, then circulate kill mud).
2. **Wait and Weight Method** – One circulation (pump weighted mud once).

What keeps BHP steady:

- Correct mud weight
- Correct pump strokes (SPM)
- Choke control

Example:

During the first circulation in the Driller's Method, if the influx is gas, casing pressure rises as gas expands — the driller holds *drill pipe pressure constant* using the choke.

Insight:

Every movement on the choke affects bottom hole pressure — control it, and you control the well.

7.3 Start-Up Procedure and Slow Pump Rates

What it is:

The *start-up procedure* begins every kill operation. It ensures BHP stays constant as circulation starts.

Why it matters:

If the choke isn't adjusted correctly during pump start-up, the sudden flow can reduce BHP and let in more formation fluid.

Procedure:

- Keep casing pressure constant while bringing pumps up to speed.
- Coordinate between driller and choke operator (slow, steady communication).
- Once at *kill rate*, note drill pipe pressure = **SIDPP + SCRP.**
- Use this value as your baseline for further calculations.

Why use slow pump rates:

- Gives more reaction time to adjust choke.
- Reduces friction losses and surface pressures.
- Prevents separator overload and improves mud control.

Example:

A 30 SPM kill rate allows the choke operator enough time to maintain pressures within limits without overshooting.

Insight:

Slow is smooth, and smooth keeps the well balanced.

7.4 Driller's Method

Purpose

- Maintain constant BHP while removing influx and replacing mud.
- Uses **two circulations** to safely kill the well.

First Circulation

1. Circulate influx out of the well using **original mud weight**.
2. Maintain **Initial Circulating Pressure (ICP)** = SIDPP + SCR.
3. Bring the pump to **kill rate slowly** (about one minute).
4. Hold **constant casing pressure** while circulating.
5. Do **not** change choke settings unless casing pressure trends of target.

Example:

The first circulation clears the influx but does **not yet balance** the well with kill-weight mud.

Second Circulation

1. Begin pumping **kill-weight mud** into the system.
2. Maintain BHP constant by adjusting the choke as heavier mud moves downhole.
3. Watch for **pressure reductions** as the kill mud replaces lighter mud.
4. Once kill mud returns to surface — the well should be balanced.

Note:

The second circulation completes the kill operation — any pressure discrepancy indicates trapped gas or miscalculation.

Advantages

- Simple to perform and calculate.
- Minimal preparation required.
- Useful for training and verification of well data.

Disadvantages

- Takes longer — two full circulations.
- Higher surface pressure on first circulation.
- Requires precise choke control during both cycles.

Insight:

Driller's Method trades **speed for control** — giving more time to observe well behavior and confirm stable pressures.

7.4 Wait and Weight Method

Purpose

- Reduce total casing pressure and kill the well in a **single circulation**.
- Requires **accurate pre-calculated pressures** and coordination between mud and choke operators.

Process Steps

1. Mix **kill-weight mud** before starting the circulation.
2. Start pumping at kill rate while following the **predetermined pressure schedule**.
3. Maintain BHP by adjusting choke according to planned pressures.
4. Monitor pressure drops as kill mud reaches bit and displaces lighter mud.
5. When kill-weight mud returns to surface → the well is balanced.

Advantages

- Faster than Driller's Method (one circulation).
- Lower casing pressure throughout operation.

- Reduces total pump strokes and surface wear.

Disadvantages

- Requires accurate calculations before pumping.
- Greater crew coordination and timing required.
- Mistimed choke adjustments can underbalance or overpressure the well.

Example:

The Wait and Weight Method is preferred when mud mixing is fast, calculations are confirmed, and time on bottom is critical.

Insight:

This method saves time but demands **precision** — every adjustment affect bottom-hole pressure in real time.

7.5 Practical Application of Kill Methods

What it is:

Translates theory into practice — performing both **Wait and Weight** and **Driller's Method** with real numbers and conditions.

Why it matters:

Understanding how to apply pressure schedules and monitor well response is critical to safely executing a kill.

Core Example Data:

- TVD = 10,000 ft
- SIDPP = 500 psi
- SICP = 1000 psi
- Current Mud = 10 ppg
- SCRP = 300 psi @ 30 SPM

Key Calculations:

1. **Kill Mud Weight (KMW)** = (SIDPP ÷ (TVD × 0.052)) + OMW = 11.0 ppg
2. **Initial Circulating Pressure (ICP)** = SIDPP + SCRP = 800 psi
3. **Final Circulating Pressure (FCP)** = SCRP × (KMW ÷ OMW) = 330 psi
4. **Step-Down Chart:** Pressure reduces ~47 psi per 100 strokes

Example – Wait & Weight:

Follow the step-down chart as kill mud displaces the influx — casing pressure rises while pit volume increases until clean mud returns.

Example – Driller's Method:

Hold *drill pipe pressure constant* at ICP through the first circulation; circulate influx out, then pump kill mud in the second.

Insight:

Precision matters — 100 psi too high or low can turn a routine operation into a control loss.

7.6 Considerations During Well Control

Purpose

To ensure pressure remains constant, formation integrity is maintained, and operational control is never lost. Every action affect bottom-hole pressure (BHP).

Key Considerations

1. **Communication**
   - Maintain clear communication between Driller, Choke Operator, and Supervisor.
   - Use agreed hand signals or radio protocols to avoid confusion during choke adjustments.
2. **Pump Start-Up**
   - Always bring pumps up to speed **slowly** while holding casing pressure constant.
   - Verify the choke response before fully engaging.
3. **Monitoring**
   - Continuously monitor pit gain/loss, flow rates, and pressures.
   - Gas migration can occur even while pumping—track any unexpected trends.
4. **Temperature and Gas Expansion**
   - Gas expands as it rises; surface pressure may increase even with proper choke control.
   - Anticipate this behavior—adjust choke gradually.
5. **Crew Readiness**
   - Assign clear duties: choke operator, recorder, mud logger, pit watcher.
   - Keep all personnel briefed before beginning circulation.

Example:

During a Driller's Method, if casing pressure rises 200 psi while drill pipe pressure remains constant, it could indicate gas expansion approaching the surface.

Insight:

A calm, consistent choke operator is worth more than any calculation—precision and timing prevent escalation.

7.7 Pressure Profiles

Purpose

To visualize how pressures behave throughout the well during kill operations and ensure bottom-hole pressure remains constant.

Typical Pressure Behavior

Condition	Drill Pipe Pressure	Casing Pressure	BHP
Shut-in	Equal to SIDPP	Equal to SICP	Constant
Start-up	Increases to ICP	Held constant	Constant
Circulating influx	Constant	Rises as gas expands	Constant
Kill mud to bit	Drops toward FCP	Falls slowly	Constant
Kill mud to surface	Constant FCP	Returns to zero	Balanced

Example:

In Wait and Weight, the drill pipe pressure decreases as heavy mud replaces lighter mud—hydrostatic increases while backpressure drops equally.

Insight

Pressure trends tell the story. If both casing and drill pipe pressures move in the same direction — stop and verify the choke response.

7.8 Comparison of Main Methods

Feature	Driller's Method	Wait & Weight
Circulations Required	Two	One
Preparation Time	Short	Longer
Accuracy Required	Moderate	High
Surface Pressure	Higher (1st circulation)	Lower
Time to Kill	Longer	Shorter
Risk of Overpressure	Moderate	Lower
Best Use	Limited mixing capability	When precise control available

Example:

A rig with fast mud mixing capabilities and trained crew may prefer Wait and Weight. Smaller rigs with limited systems often rely on Driller's Method.

Insight

Both methods work — choose the one that your equipment and crew can execute **flawlessly**.

7.9 Problems and Bad Practices

Common Mistakes

- Failing to record accurate SCR or ICP values.
- Changing pump speed mid-kill.
- Poor choke communication or erratic operation.
- Over-tightening choke causing pressure spikes.
- Using unverified mud weights or mixing errors.

Example:

A 0.2 ppg error in kill mud weight on a 12,000-ft well can cause ±125 psi BHP difference — enough to lose control.

Insight

Most blowouts after shut-in result from **human error**, not calculation error. Calm, procedural discipline wins.

7.10 Non-Routine Well Control Procedures

Scenarios

- **Gas Migration Control**
  - If pressures increase with the well shut-in, circulate slowly through the choke.
- **Lost Returns**
  - Use a reduced weight mud and volumetric control.
- **Plugging the Bit**

- Alternate circulation paths carefully—avoid pressure surges.

- **Trapped Pressure in BHA**
    - Bleed of slowly to prevent shock loading.

Example:

When performing a volumetric method, allow gas to expand under control while bleeding casing pressure to keep BHP constant.

7.11 Completions and Workover Considerations

When Working Over Wells

- Fluid columns may differ due to tubing or packer setup.
- Pressure control relies on both **surface barriers** and **fluid barriers**.
- Never displace completion fluids without calculating equivalent mud weights.

Key Steps

1. Confirm isolation integrity (packer test).
2. Record tubing and annulus pressures.
3. Maintain constant BHP with fluid changes.
4. Use weighted brine if applicable.

Insight

Workovers carry unique risks — smaller margins for error, more equipment barriers, and often less space to react.

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SECTION 8 – CALCULATIONS

8.1 – Introduction

In well control, numbers tell the story. Pressures, volumes, and gradients form the foundation for every decision made at the rig floor. Understanding how these figures connect allows the driller and well control team to predict, respond, and recover safely when the well becomes under pressure.

Every equation in this section exists to help maintain hydrostatic balance and control formation pressure. Once you know how each value influences the system, the math stops being theory—it becomes operational sense.

Key Focus Areas:

- Hydrostatic pressure and gradients
- Formation and fracture pressures
- Annular capacities and volumes
- Kill mud weight (KMW)
- Circulating pressures (ICP & FCP)
- Maximum allowable surface pressure (MAASP)
- Kick tolerance and gas behavior

Example:

Before drilling ahead, you calculate expected hydrostatic pressure. If mud weight is 10.0 ppg and true vertical depth (TVD) is 10 000 ft:

$0.052 \times 10.0 \times 10000 = 5200$psi.

Knowing this confirms the well is currently overbalanced/underbalanced/balanced.

Reflection:

When you look at a well control sheet, which number tells you whether you're winning or losing control—and why?

Insight:

Math doesn't control the well—your understanding of it does.

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8.2 – Mud Volumes

Mud volumes connect the surface system to what's happening downhole. When pit levels change, the mud system is talking—if you can read it correctly.

Basic Volume Formulas

- Rectangular tank: L × W × H = ft^3
- Cylindrical tank: (rr/4) × D^2 × H = ft^3
- Convert: 1 bbl = 5.6146 ft^3

Field Application

Trip tanks and active pits must be calibrated so that the volume indicated on the gauge equals the actual mud added or removed. Even small mis-reads create false kick signals or hide real influxes.

Example:

Adding 10 bbl to a calibrated trip tank causes the indicator to move exactly the expected distance. When it doesn't, something is of—often trapped fluid in lines or incorrect calibration.

Good Habits

- Calibrate tanks whenever piping is changed.
- Record change in volume, not absolute numbers.
- Watch for line fill or displacement effects when circulating.

Reflection:

What's your go-to confirmation that a pit gain is real and not a measurement error?

Insight:

The pit room is your first early-warning system—trust it when it's accurate.

8.3 – Core Well Control Formulas

These are the everyday calculations that make up a driller's decision-making toolkit.

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Concept	Formula	Notes
Hydrostatic Pressure	$P_h = 0.052 \times MW\ (ppg) \times TVD\ (ft)$	Pressure exerted by mud column
Annular Capacity	$V_{ann}\ (bbl) = \frac{D^2 - d^2}{1029.4} \times L$	Volume between casing and pipe
Pipe Capacity	$V_{pipe}\ (bbl) = \frac{ID^2}{1029.4} \times L$	Used for stroke calculations
Kill Mud Weight	$KMW = MW\ now + \frac{SIDPP}{0.052 \times TVD}$	Balances formation pressure
Initial Circulating Pressure	$ICP = SIDPP + SCRP$	Starting pump pressure
Final Circulating Pressure	$FCP = SCRP \times \frac{KMW}{MWnow}$	End-of-kill pressure
MAASP	$(MW_{lot/fit} - MW_{now}) \times 0.052 \times TVD_{shoe}$	Fracture-pressure limit

Gas Law	$P_1 V_1 = P_2 V_2$	Predicts expansion as gas rises

Example:

If SIDPP = 900 psi, MW = 10.0 ppg, and TVD = 10 000 ft,

$$KMW = 10 + \frac{900}{0.052 \times 10000} = 11.7 ppg.$$

This new weight will balance formation pressure once the kill is complete.

Reflection:

Which three formulas do you rely on most when checking a kill sheet—and why those?

Insight:

Accuracy in math builds confidence in the choke line.

8.4 – Calculations

Part 4 – Strokes to Pump and Displacement

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Pump strokes translate volume into action. Knowing how many strokes move fluid from the surface to the bit—and back up the annulus—keeps you in sync with the well during a kill.

Key Formula

$$Strokes = \frac{V_{string}}{\text{Pump Output (bbl/str)}}$$

where

V_{string}= volume inside the drill string (bbl)

Pump Output = fluid moved per stroke (bbl/stk)

Surface-to-Bit and Bit-to-Surface

- **Surface → Bit** = fill the drill string
- **Bit → Surface** = displace annular volume

Track these carefully during kills, stripping, or reverse circulation.

Example:

A 0.098 bbl/stk pump must move 25 bbl through the string.

$$\frac{2s}{0.098} = 255 strokes.$$

If you're 30 strokes of, check line fill or pump calibration.

Reflection:

Do you trust your stroke counter more than your gauge—and why?

Insight:

Every stroke counts; your math keeps the well honest.

8.5 – Formation Pressures

Formation pressure drives every kick and every kill. If you can predict it, you can control it.

Normal, Abnormal, and Sub-Normal

- Normal: matches hydrostatic pressure of seawater (� 0.465 psi/ft)
- Abnormal: greater than normal—risk of kick
- Sub-normal: less—risk of loss circulation

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Determining Formation Pressure

$$P_{form} = 0.052 \times MW_{eq} \times TVD$$

Use LOT or FIT data to confirm safe limits before drilling deeper.

Example:

LOT = 13.0 ppg at 9 000 ft ➔ Fracture Pressure � 0.052 x 13.0 x 9 000 = 6 084 psi.

Stay below this during kills to avoid breaking the shoe.

Good Practice

- Recalculate whenever mud weight changes.
- Always compare formation pressure vs fracture pressure margin (MAASP).

Reflection:

How do you verify your kill plan won't exceed the shoe's fracture limit?

Insight:

The formation sets the rules—your pressure plays within them.

8.6 – Hydrostatic and Gradients

Hydrostatic pressure is the foundation of well control. If you can calculate it in your head, you're never caught of guard.

Formulas

- Hydrostatic Pressure: $P = 0.052 \times MW \times TVD$
- Pressure Gradient: $G = 0.052 \times MW$(psi/ft)
- Equivalent Mud Weight for a Pressure: $MW = \dfrac{P}{0.0s2 \times TVD}$

Understanding Gradients

Every fluid column exerts a pressure based on its density and depth.

Higher MW means higher pressure gradient—useful for holding formation pressure, but risky for lost returns if too high.

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Example:

At 10 000 ft with 10.0 ppg mud, gradient = 0.52 psi/ft; pressure = 5 200 psi.

If you switch to 12.0 ppg, pressure becomes 6 240 psi—1 040 psi more on the formation.

Practical Use

- Compare mud and formation gradients to judge balance.
- Translate pressures to MW for easy communication with the mud engineer.

Reflection:

When do you mentally calculate pressure gradients on the rig?

Insight:

If you can picture the pressure in your head, you're already ahead of the well.

8.7 – Equivalent Circulating Density (ECD)

When you circulate, friction adds pressure to the bottom of the hole.

The combination of hydrostatic and friction pressure is called Equivalent Circulating Density (ECD) — the true pressure your formation feels while pumps are on.

Formula

$$ECD = MW + \frac{Apl}{0.052 \times TVD}$$

Where:

- MW = mud weight (ppg)
- ApL = annular pressure loss (psi)
- TVD = true vertical depth (ft)

Field Use

ECD shows how close you are to the fracture limit.

If ECD > fracture gradient, the well will lose returns; if too low, gas may enter.

Example:

MW = 12 ppg, TVD = 10 000 ft, ApL = 300 psi

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$$ECD = 12 + \frac{300}{0.052 \times 10000} = 12.6 ppg$$

A 0.6 ppg increase can make the difference between safe circulation and a loss.

Reflection:

When do you stop circulation to check if friction is affecting your margin?

Insight:

ECD turns numbers into feel — it's how you know what the formation feels when you pump.

8.8 – Kick Tolerance

Kick tolerance measures how much influx you can take before exceeding your casing shoe strength.

It's the line between manageable and catastrophic.

Formula

$$\text{Kick Tolerance (ppg)} = \frac{P_{frac} - P_{surf} - P_{hydro}}{0.052 \times TVD}$$

or, simplified for volume:

$$\text{Kick Tolerance (bbl)} = \frac{MAASP}{0.052 \times TVD \times (MW - G_{influx})/G_{mud}}$$

Field Use

Plan ahead — if your kick tolerance is small, the kill window is tight and mud must be adjusted before drilling ahead.

Example:

At 9 000 ft, fracture pressure = 6 100 psi, current mud pressure = 5 000 psi ➔ difference = 1 100 psi.

$$\text{Kick tolerance} = \frac{1100}{0.0s2 \times 9000} = 2.35 ppg margin.$$

That's a narrow safety window.

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Reflection:

If your kick tolerance dropped by half overnight, what would you check first?

Insight:

Knowing your limit before the well tests it is true control.

8.9 – Gas Expansion and Behavior

Gas expands as it rises — fast, powerful, and predictable.

Understanding this is key to managing kicks safely.

Boyle's Law

$$P_1V_1 = P_2V_2$$

As pressure drops, volume increases proportionally.

Example:

If a gas bubble at 10 000 ft (5 200 psi) is 1 bbl, at the surface (~14.7 psi):

$$V_2 = \frac{P_1}{P_2} \times V_1 = \frac{5200}{14.7} \times 1 \approx 354\text{bbl}$$

That's why controlled circulation is vital — uncontrolled gas rise means uncontrolled volume expansion.

Practical Use

- Maintain constant bottomhole pressure with choke control.
- Circulate slowly enough to let gas expand and bleed of safely.
- Recognize that even a small gas influx at depth can become huge at surface.

Reflection:

What's the best way to control a kick when you know it contains gas?

Insight:

Gas doesn't wait for you to calculate — it expands anyway. Control it before it controls you.

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8.10 – Kick Intensity

Kick Intensity tells you *how strong the formation is pushing back*.

It is the difference between the formation pressure and your current hydrostatic pressure. This difference determines how much extra mud weight you'll need to regain control.

Formula

$$\text{Kick Intensity (psi)} = P_{form} - P_{hydro}$$

or expressed in mud weight:

$$\text{Kick Intensity (ppg)} = \frac{\text{SIDPP}}{0.052 \times \text{TVD}}$$

Field Use

Kick Intensity converts the surface reading (SIDPP) into a pressure gradient you can understand in ppg.

It's the foundation for calculating the Kill Mud Weight.

Example:

SIDPP = 700 psi, TVD = 10 000 ft ➔

$$\text{Kick Intensity} = \frac{700}{0.052 \times 10\,000} = 1.35\text{ppg}$$

If your current mud is 10 ppg, you'll need � 11.35 ppg to balance the formation.

Reflection:

What part of your shut-in readings tells you the kick's strength?

Insight:
Every kick speaks in pressure — kick intensity is its voice.

8.11 – MAASP Checks

MAASP – Maximum Allowable Annular Surface Pressure

This is the upper safe limit at the choke manifold.

If exceeded, you risk fracturing the casing shoe or losing returns.

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Formula

$$MAASP = (MW - MW_{now}) \times 0.052 \times \text{Shoe TVD}$$

where

- MW = fracture equivalent mud weight from LOT/FIT
- MW now = current mud weight

Field Use

During a kill, monitor casing pressure against MAASP constantly.

It defines how much choke pressure you can safely apply.

Example:

Shoe TVD = 9 000 ft, MW = 10 ppg, MW= 13 ppg

$$MAASP = (13 - 10) \times 0.052 \times 9\,000 = 1\,404 \text{psi}$$

Keep surface pressure below � 1 400 psi during kill.

Reflection:

How often do you check your MAASP during a well kill operation?

Insight:
MAASP is your safety fence — stay inside it and you stay in control.

8.12 – Kill Sheet Application

A kill sheet organizes every number that keeps a kill steady. It's both your checklist and your action plan.

Core Entries

- TVD and current mud weight
- SIDPP / SICP
- SCRP (Static Circulating Pressure)
- KMW, ICP, FCP

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- MAASP
- Pump output (bbl/stroke) and strokes to bit

How to Use

1. Fill out the sheet before circulating.
2. Double-check math with another crew member.

3. Post it at the choke panel and record actual pressures as you pump.
4. Update it immediately if mud weight or depth changes.

Example:

You record SIDPP = 850 psi, SCRP = 300 psi, TVD = 10 000 ft, MW = 10 ppg. KMW = 11.6 ppg, ICP = 1 150 psi, FCP = 348 psi.

These values form your circulation roadmap.

Reflection:

When was the last time you recalculated your kill sheet after mud weight changed?

Insight:

Preparation beats panic — a kill sheet filled early saves seconds later.

8.13 – Putting It All Together (Summary)

All the formulas, pressures, and volumes connect into one purpose — balance.

When you understand how each number relates to another, you no longer just fill out a kill sheet — you control the well with intent.

Key Takeaways

- Pressure relationships: hydrostatic + annular + formation = system pressure.
- Hydrostatics hold the well; circulating friction changes the load; fracture pressure sets your ceiling.
- Volumes and capacities guide displacement and monitoring.
- Kick detection and gas behavior show how quickly things can change.
- Kill sheets and MAASP checks keep the operation inside safe limits.

Why It Matters

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Every well control event, from a small gas bubble to a major kick, is solved by applying these fundamentals.

You may never see a perfect scenario, but the math keeps your decisions consistent when pressure, noise, and time start working against you.

Example:

You shut in a well showing SIDPP = 850 psi and SICP = 1 050 psi.

You calculate KMW = 11.6 ppg, MAASP = 1 400 psi, and ECD = 12.4 ppg.

Because you understand the relationships, you can guide the choke, maintain bottomhole pressure, and stay below fracture limits — safely killing the well.

Reflection:

When everything is happening fast, which three calculations do you instinctively check first — and why?

Insight:

Formulas are more than math — they're the language of control. Speak them fluently, and the well listens.

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9 – Well Control Equipment

9.1 – Introduction to Well Control Equipment

Purpose

The well control system provides the means to **control, direct, and circulate fluids** safely during drilling operations. It prevents uncontrolled release of formation fluids to the surface and maintains wellbore integrity.

This section covers the surface pressure control system, which includes:

- The Blowout Preventer (BOP) Stack
- The Accumulator Unit and Control System
- The Choke and Kill Manifold
- The Mud-Gas Separator and Diverter System

How It Works

When formation pressure exceeds hydrostatic pressure, fluids can low into the wellbore.

If that happens:

1. The BOP stack seals the well.
2. The accumulator provides the hydraulic energy to operate those functions.
3. The choke manifold allows controlled circulation of the influx.
4. The mud-gas separator safely handles and vents gas at the surface.

Each piece works together to ensure the well can be shut in, held, and circulated in a controlled manner.

Example:

A driller detects an increase in low rate and closes the annular preventer. The accumulator provides stored hydraulic pressure to activate the function. The choke manifold is then aligned, and pressure is managed while circulating the influx through the mud-gas separator to the flare line. Each component acts as a link in one complete safety system.

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When It Matters

- While drilling through pressure transitions or unknown formations.
- During tripping, casing, and cementing.
- Anytime the mud column might not hold formation pressure.

Risks / Watchouts

- Unverified valve positions.
- Low accumulator pressure.
- Leaks or obstructions in the control system.
- Inadequate testing or maintenance.

Your Thoughts:

What systems on your rig make up the secondary barrier — and how often are they tested?

Insight:

The well control system isn't one piece of equipment — it's teamwork between barriers, steel, and people.

9.2– Blowout Preventer (BOP) Stack

Purpose

The BOP stack provides a mechanical barrier that can seal the wellbore, control pressure, and contain formation fluids during well control operations.

How It Works

The stack normally consists of one annular preventer on top of a series of ram preventers mounted on the wellhead.

Choke and kill lines are connected to spools between preventers, allowing fluid circulation when the well is shut in.

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Types of BOPs:

- Annular Preventer:
    - Seals around any shape (drill pipe, tool joints, or open hole).
    - Common working pressure: 3,000–10,000 psi.
    - Operated by hydraulic pressure from the accumulator system.
- Ram Preventers:
    - Pipe Rams: Seal around specific pipe diameters.
    - Blind Rams: Seal when no pipe is in the hole.
    - Shear Rams: Cut pipe and seal in an emergency. A typical land

stack is arranged:

- Annular on top.
- Pipe rams below.
- Blind or shear rams on bottom.

Choke and kill outlets are located between preventers, with Hydraulic Control Remote (HCR) valves for isolation.

Testing and Operation

- Function Tests: Verify mechanical movement and seal integrity.
- Pressure Tests: Confirm the stack holds pressure at rated working limits.
- Annular Closing Time: :: 30 seconds.
- Ram Closing Time: :: 45 seconds.
- Test Pressures:
    - Low pressure: 250 psi.
    - High pressure: per manufacturer rating (often 5,000 or 10,000 psi).

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Example:

While drilling, the well begins to low. The driller closes the annular preventer using 1,500 psi hydraulic pressure. Once stabilized, the pipe rams are closed for long-term pressure containment. Choke and kill lines are aligned to circulate the influx out through the manifold.

When It Matters

- Kick detection or control.
- During BOP tests, maintenance, and inspections.
- Drilling out casing shoes or through high-pressure zones.

Risks / Watchouts

- Wrong ram size for pipe OD.
- Over-pressuring annular packing element.
- Choke or kill valves misaligned.
- Incomplete function or pressure testing.

Your Thoughts:

Why is it critical to always close the annular first when shutting in a well?

Insight:

Annulars seal everything — rams lock in control for the long run.

9.3 – Accumulator Unit and Control System

Purpose

The accumulator provides the hydraulic power needed to operate all BOP functions — even if rig power fails. It's the "heart" of the well control system.

How It Works

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The system uses compressed nitrogen and **hydraulic fluid** to store and deliver energy.

- Nitrogen bottles are pre-charged to 1,000 psi.
- Hydraulic pumps charge the bottles to system operating pressure, typically 3,000 psi.
- When a function is activated, pressurized fluid lows to BOP actuators through the control manifold.
- Sequence valves ensure proper operation pressure for annulars, rams, and HCR valves.

Control panels allow operation from the driller's station, the accumulator unit, or a remote location.

Performance Requirements:

- Must close the annular and two ram preventers without pump assistance.
- Maintain at least 200 psi above precharge pressure after all functions are complete.
- Pump-up time: :: 5 minutes to recharge system pressure.
- Function test frequency: Every 14 days or per company procedure.

Example:

During a test, the annular close time is 35 seconds — above the 30-second limit. After checking, technicians find precharge pressure has dropped to 800 psi. Recharging the nitrogen to 1,000 psi restores closing time to 28 seconds, meeting the standard.

When It Matters

- Before drilling into high-pressure or unknown formations.
- After bottle replacement, valve service, or leaks.
- Anytime BOP closing speed slows.

Risks / Watchouts

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- Low nitrogen precharge (below 1,000 psi).
- Hydraulic fluid contamination.
- Leaks or blocked control lines.
- Incorrect sequence valve settings.

Your Thoughts:

If your annular closes too slowly, what should you check first — and why?

Insight:

Your BOP is only as strong as the energy feeding it. Keep the accumulator charged, and you keep control.

9.4 – Choke and Kill Manifold System

Purpose

The choke and kill manifold provides controlled low paths to circulate fluids during well control operations.

It allows the driller to manage casing pressure and circulation rates while safely removing an influx from the well.

This system connects directly to the BOP stack and plays a critical role in maintaining surface pressure within safe limits.

How It Works

The choke manifold is made up of high-pressure valves, chokes, and lines rated to the same working pressure as the BOP stack (commonly 5,000 psi, 10,000 psi, or 15,000 psi).

Functions of the Manifold:

- Controls pressure on the casing during circulation.
- Allows fluid circulation from the well through the choke.
- Directs low to the mud-gas separator or fare line.
- Provides secondary low paths for safety and maintenance.

A typical manifold includes:

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- Two chokes: One *manual* and one *hydraulic remote*.
- Four or more gate valves: To isolate, equalize, or direct low.
- Pressure gauges: To monitor casing and choke line pressure.
- Equalizing valves: To switch between chokes safely.

Operation Steps:

1. When the BOP is closed, low is directed from the casing outlet to the choke manifold.
2. The operator adjusts the choke to control casing pressure and maintain the desired circulating pressure.
3. Fluid is routed through the **low line** to the mud-gas separator for safe handling.
4. The kill line allows pumping of heavier mud into the well to displace the influx.

Example:

During a kill operation, casing pressure is held at 600 psi. As circulation begins, the choke is gradually opened to maintain a constant drill pipe pressure. The kill mud is pumped down the kill line at 3 bpm, circulating the gas influx to surface while controlling pressure on both sides of the well.

When It Matters

- During well control circulation (Driller's or Wait & Weight Method).
- During equipment pressure testing.
- When verifying low paths or performing choke drills.

Risks / Watchouts

- Opening both chokes simultaneously (uncontrolled low).
- Equalizing valve left open between chokes.
- Plugging due to solids or barite in choke line.

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- Incorrect valve alignment or untested seals.

Your Thoughts:

Why is it critical to always line up and pressure test the choke manifold before drilling out casing shoes?

Insight:

The choke manifold is your steering wheel in a well control event — smooth hands keep pressure steady.

9.5 – Gas Handling and Diverter Equipment

Purpose

Gas handling equipment ensures safe separation and venting of gas during well control operations. It prevents gas from entering the mud tanks, reduces fire risk, and directs hazardous gases away from personnel.

How It Works

After the well is shut in and circulation begins, the returning mixture lows through the mud-gas separator (MGS), sometimes called a poor boy degasser. Inside the separator:

1. Gas and mud enter the vessel through a tangential inlet line.
2. Gas separates and exits the vent line to the flare.
3. Mud falls to the bottom and returns to the active mud system. Typical

separator design:

- Working pressure: 100 psi (tested to 1.5x rated).
- Gas vent line backpressure: < 10 psi.
- Capacity: 1,000–3,000 gpm, depending on rig size.
- Vent line directed ;; 100 ft away from rig and ignition sources.

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The diverter system is used primarily for shallow gas or top-hole drilling, where the well is not yet fully equipped with a BOP stack.

It redirects uncontrolled low away from the rig floor to a safe discharge area.

Diverter Components:

- Diverter housing and annular-type sealing element.
- Large-diameter vent lines (minimum 10 in.) with quick-opening valves.
- Flow paths leading to a pit or flare line.

Diverter Operating Requirement:

- Must open and fully divert low within 45 seconds of activation.
- Diverter valves and lines are pressure-tested before each use.

Example:

While drilling top hole, a shallow gas zone is encountered. The annular closes, the diverter valves open automatically, and gas is safely redirected through 10-inch vent lines to the pit. The crew remains safe because the diverter operated as designed within seconds.

When It Matters

- During well control circulation (gas handling).
- Drilling top-hole intervals (diverter system).
- When venting or flaring gases during controlled kill operations.

Risks / Watchouts

- Blocked or frozen vent lines.
- Insufficient fare distance or poor line grounding.
- Separator overpressure due to backpressure in vent line.
- Diverter system not fully open before low begins.

Your Thoughts:

What could happen if the mud-gas separator vent line is too short or restricted?

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Insight:

Gas never asks for permission — it takes the path you leave open. Always give it a safe one.

9 – Well Control Equipment

9 Summary – Well Control Equipment

The surface well control system is more than machinery — it's a chain of barriers that work together to keep pressure where it belongs. Each link depends on the next:

1. Introduction to Well Control Equipment –
   The system's purpose is simple: control, direct, and circulate fluids safely.
   From the BOP to the flare line, every valve and sensor plays a part in preventing an uncontrolled release.
2. Blowout Preventer (BOP) Stack –
   The BOP is the mechanical barrier that seals the well.
   Annulars seal around anything; rams lock the pressure down tight.
   Regular testing, proper ram sizing, and correct valve alignment turn hardware into confidence.
3. Accumulator Unit and Control System –
   Stored hydraulic energy makes the BOP respond instantly.
   A 1,000 psi nitrogen precharge and 3,000 psi system pressure keep every function alive when power fails.
   If energy is low, so is control — and time is never on your side.
4. Choke and Kill Manifold System –
   The manifold is the crew's steering wheel during a kick.
   By adjusting chokes, the driller balances casing and drill pipe pressure to remove the influx safely.
   Clean line-ups, tested valves, and disciplined control prevent chaos when the well pushes back.
5. Gas Handling and Diverter Equipment –
   Once the gas is moving, it must go somewhere safe.
   The mud-gas separator, flare line, and diverter system route it away from people and

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   equipment.
   Proper line length, venting, and back-pressure control turn danger into routine low.

Together these parts form the secondary barrier — the steel, valves, and energy that protect life and equipment when the mud column can't.

Mastering this system isn't just technical; it's about trust — in your tools, your team, and your training.

Your Reflection:

Which part of the surface well control system do you personally inspect first — and why?

Insight: ısight:

When pressure tests courage, equipment answers first — but only if you prepared it to.

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Section 10 – ADDITIONAL METHODS AND TECHNIQUES

10.1 – Introduction

Purpose

Sometimes the well doesn't follow the plan. When equipment limits, formation strength, or circulation paths fail, you still need a way to regain control.

This section explains alternative methods used when standard well-kill procedures aren't possible.

How It Works

Each technique—Bull heading, Volumetric Control, Stripping, and more—uses pressure management in a different way to bring the well back under control without damaging it.

These methods depend on accurate readings, steady adjustments, and sound judgment more than brute force.

Example:

Imagine you're driving a loaded truck down a mountain in the rain. You can't rely on full brakes —you downshift, tap gently, and control the descent.

These alternative methods are the same principle: controlled, deliberate moves that protect you and the well.

When to Use These Methods

- Circulation is lost or blocked
- Formation or casing pressure limits prevent standard kill
- Gas is migrating up hole
- Equipment failure prevents normal pumping

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Risks / Watchouts

- Over- or under-pressuring can worsen the situation
- Requires precise coordination between crew and choke operator
- These are *controlled-risk* methods—use with full awareness

Your Thoughts:

When would you decide to stop the standard kill and switch to an alternate control method?

Insight:
Control isn't strength—it's precision under pressure.

10.2 – Bull heading

Purpose

Bull heading is a last-resort method used when you can't safely circulate a kick to surface. It pushes the influx back into the formation using controlled pump pressure.

How It Works

Kill-weight mud or heavy fluid is pumped down the casing or tubing with enough pressure to overcome:

- The hydrostatic head of existing fluid,
- The surface pressure from the influx, and
- Friction losses through lines and valves.

When those forces balance, the influx is pushed back into the formation, and the well is then shut in to confirm stability.

Formula Reference:

Hydrostatic Pressure (psi) = 0.052 × Mud Weight (ppg) × True Vertical Depth (ft)

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Example:

Think of closing a heavy gate against strong wind—you lean in slowly, steady, never slamming. That's bull heading: using steady control to push pressure back where it belongs without breaking what's holding it.

When to Use It

- Circulation path blocked or bit off bottom
- Pumps or drill string damaged
- High H2S content prevents surface handling
- Formation too weak for full-pressure kill
- Workover or completion operations with limited flow paths

Risks / Watchouts

- Too much pressure � formation fracture or casing failure
- Too little � incomplete displacement / gas migration
- May cause lost returns or need for secondary circulation

Your Thoughts:

Before starting a bullhead operation, what three limits must you confirm first?

Insight:
Bull heading isn't about force—it's controlled power applied with discipline.

10.3 – Volumetric Control

Purpose

The Volumetric Method manages gas migration when you can't circulate. It maintains bottomhole pressure while gas expands and moves upward.

How It Works

As gas rises, the pressure above it decreases, allowing expansion. That expansion raises both casing and bottomhole pressure.

By bleeding off small, measured volumes of mud, you reduce hydrostatic pressure by the same amount the gas expansion increases it—keeping the well balanced.

Working Formula Example:

Pressure Change (psi) :: 0.052 x Mud Weight (ppg) x Volume (bbl) --- Annular Capacity (bbl/ft)

You repeat the bleed-off cycle in steps (commonly :: 100 psi increments) until the gas reaches surface or you can circulate normally again.

Example:

Picture loosening a jar lid slowly to let pressure escape—you don't twist it wide open; you ease it, listening for the hiss.

That's volumetric control: small, deliberate releases that prevent a blowout of stored energy.

When to Use It

- Pumps unavailable or string plugged
- Gas migration during shut-in
- Drill string out or off bottom
- Need to manage pressure without breaking formation

Risks / Watchouts

- Bleeding too fast � underbalance, new influx

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- Bleeding too slow � overpressure, possible fracture
- Requires accurate pressure readings and calm operation
- Gas expansion increases rapidly near surface—anticipate it

Your Thoughts:

How would you explain to a new driller why "slow" is safer during volumetric control?

Insight:

Every barrel bled off is a step closer to balance—listen to what the well tells you.

10.4 – Stripping Operations

Purpose

Stripping is used to run pipe back into a shut-in well while keeping it under control.

The goal is to maintain bottomhole pressure slightly above formation pressure as pipe is stripped in or out, preventing another influx or losses.

How It Works

Stripping involves carefully opening the pipe rams, lowering pipe through the BOP stack, then closing rams again before bleeding off the small pressure increase caused by pipe displacement. Every stand or joint moved changes the volume in the well, which changes pressure. By tracking that pressure change and bleeding off the right amount of mud, the well stays balanced.

Reference:

Each foot of pipe run into the well displaces mud:

Pressure Increase (psi) :: 0.052 x Mud Weight (ppg) x Displaced Volume (bbl) --- Annular Capacity (bbl/ft)

Example:

Think about lowering a boat into a full pool — as it goes in, the water rises and spills over. Stripping is the same idea: every foot of pipe you push in raises the fluid level and pressure, so you must let a little out to keep balance.

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When to Use It

- To run pipe back to bottom after shutting in on a kick
- When circulation isn't possible but pipe needs repositioning
- During workover or completion with trapped pressure below BOPs
- To recover control tools or re-establish well access

Risks / Watchouts

- Moving pipe too quickly � over-pressure and possible losses
- Poor communication between driller and choke operator � pressure spikes
- Incorrect displacement calculations � underbalance or influx
- Always verify BOP integrity before starting

Your Thoughts:

What makes coordination between the choke operator and driller so critical during stripping?

Insight:

Stripping is a conversation between iron and pressure — move slow enough to listen.

10.5 – Lubricate and Bleed Method

Purpose

The Lubricate-and-Bleed method is used to remove a gas influx from a closed well when circulation can't be established.

It slowly replaces gas with heavy mud by alternating between pumping small "lubricating" volumes of mud and bleeding gas off at the choke.

How It Works

1. Pump a measured volume of kill-weight mud into the well.
2. Close valves and allow the gas to migrate upward and compress.

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3. Bleed off the gas until casing pressure returns to the target level.
4. Repeat the process until the well is filled with heavy mud.

Each cycle adds a bit more mud and removes a bit more gas, keeping bottomhole pressure constant without shocking the formation.

Concept Formula:

Hydrostatic Gain (psi) = 0.052 x Mud Weight (ppg) x Volume of Mud Added (bbl) --- Annular Capacity (bbl/ft)

Example

Picture adding water to a soda bottle that's partly full of fizz — pour a little in, let gas escape, repeat.

If you pour too fast, it overflows; too slow, nothing changes.

Lubricate-and-Bleed is that same balance between patience and precision.

When to Use It

- Pumps available but circulation path uncertain
- Need to remove trapped gas below BOPs
- Gas bubble too small to justify full kill circulation
- Used after volumetric control to clear remaining gas

Risks / Watchouts

- Pumping too much mud at once � formation fracture
- Bleeding too quickly � underbalance, new influx
- Requires accurate volume measurement and constant communication
- Never exceed casing shoe or MAASP limits

Your Thoughts:

Why is patience the most important tool during the Lubricate-and-Bleed process?

Insight:

Control comes from rhythm — pump, pause, bleed, repeat until the well breathes easy again

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10.6 – Off-Bottom Kill

Purpose

The Off-Bottom Kill method is used when the drill string is not on bottom but you must still circulate and kill the well.

It's often applied after a shut-in when pipe movement or well conditions prevent returning to bottom before regaining control.

How It Works

Kill-weight mud is pumped down the string while returns are taken through the annulus. Because the bit isn't at total depth, part of the wellbore remains open and full of influx. The key is to circulate carefully to remove that influx without swabbing or breaking down the formation. Maintaining correct pump rates and monitoring pressures ensures that hydrostatic head slowly overtakes formation pressure.

Formula Reminder:

Hydrostatic Pressure (psi) = 0.052 × Mud Weight (ppg) × True Vertical Depth (ft)

Example

Think of siphoning fuel from a tank when your hose isn't all the way to the bottom—you can still clear most of the liquid, but you have to control the flow to avoid drawing air or spilling. An Off-Bottom Kill works the same way—steady, cautious circulation until control is regained.

When to Use It

- Pipe can't be safely stripped to bottom
- Hole problems (bridges, cuttings) prevent full depth entry
- Kick taken while tripping or running casing
- Must kill the well before conditioning the hole

Risks / Watchouts

- Incomplete influx removal � secondary migration
- Excessive pump speed � swab or formation damage
- Poor pressure monitoring � underbalance or fracture

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- May require follow-up full circulation once bottom is reached

Your Thoughts:

What indicators tell you the well is stable enough to complete an Off-Bottom Kill safely?

Insight:

Patience beats power—let the mud column, not the pumps, do the heavy lifting.

10.7 – Casing and Cementing Considerations

Purpose

During casing and cementing, the well is in a delicate state—open formations, fluid displacement, and pressure changes can easily cause losses or kicks.

Understanding pressure balance during these operations prevents problems before they start.

How It Works

Cementing replaces mud with heavier slurry, changing hydrostatic pressure rapidly. If cement is too heavy or pumped too fast, it can fracture the formation; too light or under displaced, and formation fluids may enter the casing.

Proper spacer design, centralization, and displacement rate keep the well balanced.

Once cement sets, trapped pressure beneath plugs must be managed to avoid casing deformation or gas migration through unset cement.

Helpful Check:

Bottomhole Pressure = Hydrostatic of Fluid Column ± Applied Pump Pressure Keep within formation integrity and MAASP limits throughout cementing.

Example:

Imagine pouring concrete around a fragile pipe—too much pressure and it lifts; too little and voids form.

Cementing a casing string is no different: controlled displacement and balance keep the job strong and safe.

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When to Watch Closely

- Displacing heavy cement into weak formations
- Using lightweight or foamed cement systems
- When losses occur while circulating prior to cementing
- During plug bumping and pressure testing

Risks / Watchouts

- Formation fracture � lost returns or poor cement bond
- Gas migration through unset cement
- Over-pressurizing casing while bumping plug
- Trapped annular pressure after cement sets

Your Thoughts:

What steps would you take to prevent gas migration after cementing is complete?

Insight:

Cementing isn't just pumping—it's pressure choreography; every barrel must move with purpose.

11.1 – Introduction

Managing well control operations is about preparation, planning, and clear execution. Every kick or influx has the potential to escalate quickly—how it's handled depends on how ready the crew is.

This section covers the key parts that keep a rig safe and in control:

- Bridging Documents
- Rules and Regulations
- Barriers
- Risk Assessment
- Roles and Responsibilities
- Empowerment to Act
- Drills and Emergency Procedures
- Developing a Kill Plan
- Checklists and Handover

Well control isn't just a procedure—it's a mindset. The goal is to recognize early, act fast, and stay aligned with the plan.

Your Thoughts:

Think about a time when a small issue could have become a big one. What made the difference—reaction time, communication, or preparation?

11.2 – Bridging Documents

Every rig operates under two management systems—one from the Operator and one from the Drilling Contractor. These systems can differ in how they define responsibilities, authority, or well control procedures.

A Bridging Document exists to close those gaps. It answers:

- Whose system applies when?
- Who has final authority during well control?
- Which procedure takes precedence?

By resolving those conflicts before operations start, the rig team avoids hesitation in critical moments. Everyone knows who decides what and how to act when the unexpected happens.

Insight:

When systems aren't bridged, confusion replaces action. Bridging Documents protect people, not paperwork.

Your Thoughts:

If two supervisors gave you different instructions during a kick, which document would you rely on? Why?

11.3 – Rules and Regulations

Well control is governed by international, national, and company standards. These rules exist to ensure that every operation meets the same baseline for safety and performance—no matter the location or crew.

Typical governing bodies include:

- IADC – International Association of Drilling Contractors
- API – American Petroleum Institute
- OSHA – Occupational Safety and Health Administration (U.S.)
- Regional Regulators (e.g., CAPP in Canada, BOEM/BSEE in the U.S.)

Company policies must meet or exceed these regulatory requirements. During well control training and operations, these standards guide everything—from how barriers are tested to how blowout preventers (BOPs) are maintained.

Example:

A company may require a pit drill every 7 days even though regulation calls for 14. That difference improves preparedness—and that's the point.

Your Thoughts:

Which regulations or standards do you think impact your role the most—and why?

11.4 – Barriers

Purpose

A barrier is any means of preventing formation fluids from entering the wellbore or reaching the surface.

Understanding barriers — both physical and procedural — is the foundation of well control. Every operation, from drilling to completion, must maintain two independent barriers whenever possible.

How It Works

Barriers come in two types:

- Primary Barrier – the drilling fluid (mud column) that provides hydrostatic pressure greater than formation pressure.
- Secondary Barrier – mechanical systems like the blowout preventer (BOP), casing, and cement that contain pressure if the primary fails.

Procedural barriers also matter — trained personnel, verified equipment tests, and proper communication all help prevent failure.

When one barrier weakens, the second must be ready to hold the line.

Example:

Think of barriers like seatbelts and airbags. You don't rely on just one — both work together, and when one fails, the other must save lives.

In well control, mud is your seatbelt, and the BOP is your airbag. Both must be intact before you move forward.

When It Applies

- While circulating or conditioning mud
- During tripping, casing, cementing, or BOP testing
- After any change in mud weight, density, or pressure regime

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Risks / Watchouts

- Ignoring signs of barrier degradation (losses, gas cut mud, test failures)
- Operating with only one verified barrier
- Poor documentation or misunderstanding of what constitutes a barrier

Your Thoughts:

If one barrier weakens during operations, what immediate steps would you take to reestablish safety?

Insight:
Barriers don't fail suddenly — they erode in silence. A good driller listens before it's too late.

11.5 – Risk Assessment

Purpose

Risk assessment identifies what could go wrong, evaluates how likely it is, and determines how serious the outcome might be.

In well control, it's the difference between assuming safety and proving control.

How It Works

A risk assessment follows a structured approach:

1. Identify Hazards – gas zones, loss-prone formations, stuck pipe, underbalanced drilling.
2. Evaluate Likelihood and Severity – how often it could occur and what damage it could cause.
3. Determine Controls – what preventive or mitigating actions are in place (mud weight, crew drills, communication).
4. Monitor and Update – review risks daily and after operational changes.

Risk assessment isn't a one-time form — it's a living process that evolves as the well changes.

Example:

Before tripping out of hole, the driller notices the well lowing slightly while pumps are of. Instead of ignoring it, the team revisits their risk assessment, adds "possible gas influx," and adjusts mud weight before continuing.

That one action prevents a potential kick — proof that proactive thinking beats reactive firefighting.

When It Applies

- Before beginning new hole sections or changing mud weight
- Prior to tripping, casing, or cementing
- Whenever formation pressures or wellbore conditions change

Risks / Watchouts

- Treating risk assessments as paperwork instead of living tools
- Failing to communicate identified hazards to all crew members
- Ignoring updates when well conditions shift

Your Thoughts:

What's one example of a risk that could change overnight on your rig — and how would you catch it early?

Insight:
A strong crew doesn't just see risk — they see it coming.

11.6 – Roles and Responsibilities

Purpose

A well control event is no time for guessing who does what. Every crew member—from the driller to the shaker hand—plays a role that directly affects the safety of the entire operation.

Understanding these responsibilities ensures that actions are immediate, accurate, and coordinated.

How It Works

The Driller is the first line of defense — they monitor, recognize, and react.

The Derrickman supports the driller by managing mud systems and monitoring changes. The Shaker Hand and Mud Logger act as the eyes and ears of the operation, watching returns, low, and gas levels.

The Tool pusher and Drilling Supervisor oversee execution, ensuring the crew follows procedure and equipment operates as intended.

Together, their combined awareness keeps the operation controlled.

Example

During a low check, the driller spots a small pit gain. The derrickman verifies the mud balance, while the tool pusher confirms the pumps are of. Within seconds, the well is safely shut in — not because of luck, but because everyone knew their role.

When It Applies

- Any stage of drilling or tripping
- During drills or live well control events
- When interpreting pit or low anomalies

Risks / Watchouts

- Confusion over authority or procedure during shut-in
- Poor communication between driller and derrickman
- Failure to report small but abnormal indicators

Your Thoughts:

What actions can a derrickman or shaker hand take that directly help the driller during a potential kick?

Insight:

A well is only as safe as the communication between its crew.

Purpose

11.7 – Empowerment to Act

Empowerment is the confidence and authority for every crew member to act immediately when something's wrong.

Early action saves lives, protects equipment, and keeps control of the well.

How It Works

If an influx is suspected, the driller — or anyone in position — must act without waiting for permission.

Supervisors must foster an environment where reporting potential problems is encouraged, not feared.

Everyone has the right to stop unsafe work until the concern is resolved.

Example:

A foorhand notices pit gain during a trip but hesitates, unsure if it's his place to speak up. The delay allows more influx into the well. Contrast that with a culture where every worker knows, *"If I see it, I stop it."* That mindset prevents escalation.

When It Applies

- During tripping, drilling, or circulation
- When any sign of influx, loss, or anomaly appears
- During pre-job safety meetings and drills

Risks / Watchouts

- Crew members afraid to speak up
- Overreliance on hierarchy instead of awareness
- Lack of training or clarity on authority to act

Your Thoughts:

How does your rig reinforce that everyone is responsible for well control—not just the driller?

Insight:

Authority means nothing without trust — empower people to act, not just to obey.

11.8 – Well Control Drills

Purpose

Drills are not just a compliance requirement — they're practice for saving lives. Well control drills train crews to recognize warning signs, act quickly, and execute procedures under pressure.

How It Works

Drills simulate real events like kicks during drilling or tripping. Each drill must:

- Be realistic and structured
- Include crew participation
- Test both reaction time and understanding
- Be led and debriefed by a supervisor Common

drill types include:

- Pit Drill – Recognize a kick indicator while drilling and shut in correctly.
- Trip Drill – Detect influx while tripping and shut in using the annular preventer.
- Choke Drill – Operate the choke system under simulated conditions.
- Stripping Drill – Practice pipe movement while maintaining casing pressure.
- Diverter Drill – Respond to shallow gas or surface low with proper diverting steps. Each builds familiarity

and trust under simulated stress.

Example:

A crew that practices once a week shuts in a simulated kick in under 30 seconds. Another that only drills once a month takes nearly two minutes.

Training frequency directly equals survival odds.

When It Applies

- Before drilling out casing shoes or entering high-risk zones
- Regularly as per company or regulatory policy
- After crew changes or extended downtime

Risks / Watchouts

- Drills performed by memory, not understanding
- Skipping debriefs or reaction-time tracking
- Complacency after "passing" once

Your Thoughts:

What part of well control drills do you find most beneficial — reaction, coordination, or communication? Why?

Insight:
You don't rise to the occasion — you fall to the level of your training.

11.9 – Emergency Procedures

Purpose

Every well control event has the potential to escalate.

Emergency procedures exist so that when a situation shifts from *manageable* to *critical*, the crew knows exactly what to do — without hesitation.

How It Works

Emergency procedures are pre-planned actions for high-risk situations such as:

- Gas release or toxic exposure (H2S, CO2)
- Imminent fire or explosion risk
- Loss of control or rapid well low
- Severe weather or evacuation conditions

They include muster plans, escape routes, communication chains, and shutdown priorities.

Planning ensures the crew acts, not reacts, under pressure.

Example:

When an H2S alarm sounds, every second counts. Crews that have rehearsed muster procedures don't think — they move.

That level of readiness doesn't come from paperwork; it comes from practice.

When It Applies

- Before spud and throughout drilling operations
- Whenever hazard conditions change
- During drills or after equipment upgrades

Risks / Watchouts

- Outdated or unclear muster plans
- Crew unaware of gas detection zones or alarms
- Communication breakdown between rig floor and control room

Your Thoughts:

What's the first thing *you personally* should do if a well control emergency is declared?

Insight:
When chaos starts, structure saves.

11.10 – Developing a Plan for Kill Operations

Purpose

A well kill plan isn't written during a kick — it's developed before it happens.

Its purpose is to ensure every crew member, supervisor, and engineer knows the method, equipment, and limits before operations begin.

How It Works

A kill plan includes:

1. Selected Method: Driller's Method, Wait & Weight, or alternative technique.
2. Formation Data: Estimated formation pressure, pore pressure, and fracture gradients.

3. Circulation Details: Pump rates, choke strategy, and expected pressures.
4. Safety Margins: MAASP, casing pressure limits, and equipment ratings.
5. Contingency Steps: What happens if circulation stops or pressure exceeds limits. The plan is verified,

reviewed, and rehearsed before drilling high-pressure zones.
When a kick occurs, the team executes the plan — not a guess.

Example:
Imagine fighting a fire without knowing where the exits or hoses are. That's what killing a well without a plan looks like.

Preparation turns panic into procedure.

When It Applies

- Before entering known pressure zones
- Prior to drilling production or reservoir sections
- After any major equipment or crew change

Risks / Watchouts

- Relying on outdated or generic kill sheets
- Failing to verify choke or pump capabilities
- Miscommunication between the driller and supervisor on execution method

Your Thoughts:
What's one thing you'd check on your rig before trusting a written kill plan?

Insight:
Plans don't fail — people fail to plan.

11.11 – Checklists

Purpose

Checklists turn complex operations into simple, repeatable actions. They exist to prevent oversight and ensure consistency under pressure.

How It Works

Checklists are built for each phase of well control operations — from detection to shut-in, circulation, and kill.

They define the sequence, who performs each step, and what must be verified before continuing.

When used correctly, they *remove guesswork* and support decision-making. Example checklist areas:

- Kick detection response
- Shut-in procedure
- Kill circulation steps
- Communication low
- Handover confirmation

Example:

Airline pilots use checklists for every takeoff — not because they don't know the steps, but because mistakes happen when pressure rises.

A driller's checklist serves the same purpose: to make sure no critical valve, line, or reading is missed.

When It Applies

- Before and during well control operations
- During shift changes and crew handovers
- Anytime a new or complex procedure is executed

Risks / Watchouts

- Skipping checklist verification due to overconfidence
- Outdated or unclear documentation
- Poor handover of partially completed steps

Your Thoughts:

When was the last time you caught an error or omission because you used a checklist?

Insight:

Checklists aren't for the forgetful — they're for the focused.

11.12 – Handover

Purpose

Handover ensures that control, knowledge, and accountability transfer smoothly from one crew to the next.

A poor handover has caused more incidents than equipment failures ever have.

How It Works

A proper handover covers:

- Current well status (mud weight, depth, pressures, low)
- Ongoing operations and recent issues
- Known hazards, anomalies, or pending maintenance.
- Communication of who holds authority and next steps It's not just

paperwork — it's *passing control of the well itself*.

Example:

A night driller finishes a long shift, assuming the day crew knows about the pit level fluctuations from earlier.

Without clear communication, the next shift restarts pumps unaware — and the well lows. One missed sentence can equal one major event.

When It Applies

- At every shift change
- Between different operational crews or contractors

- Before and after critical well control operations

Risks / Watchouts

- Incomplete or rushed handovers
- Lack of written verification or acknowledgment
- Assumptions instead of confirmation

Your Thoughts:

What's one habit that could make your crew's handovers more effective and safer?

Insight:

Control doesn't end when your shift does — it ends when the next crew fully understands.

it.

Section **11** Summary – Managing Well Control Operations

Managing well control isn't just about reacting to pressure — it's about managing people, plans, and priorities under stress.

Each topic in this section builds the framework for control:

1. Introduction – Understanding that leadership and preparation define the outcome before a kick ever happens.
2. Bridging Documents – Ensuring alignment between operator and contractor so there's only one plan when seconds count.
3. Rules and Regulations – Following standards that protect lives, not just meet compliance.
4. Barriers – Maintaining two independent lines of defense — one to hold pressure, one to back it up.
5. Risk Assessment – Identifying and updating what can go wrong before it does.
6. Roles and Responsibilities – Knowing your place and trusting others to do theirs.
7. Empowerment to Act – Giving every crew member the confidence to stop work when something doesn't look right.
8. Well Control Drills – Practicing like it's real, because one day it might be.
9. Emergency Procedures – Responding to danger with precision instead of panic.
10. Developing a Kill Plan – Planning your moves before you need them.
11. Checklists – Ensuring consistency when pressure makes memory unreliable.
12. Handover – Passing control of the well, not just information.

Each part connects to the same truth — *well control starts long before a kick and never ends until communication, leadership, and verification are complete.*

Your Reflection:

Looking back through this section, which part spoke most to you — and how does it change the way you view your role in well control.

CDF TRAINING

SUPPLEMENTARY REVIEW

Well Control Knowledge & Application

Use this review to reinforce the major concepts, decisions, and calculations covered in the workbook. Choose the best answer for each question. For calculation questions, use the workbook formulas and round reasonably.

Calculation notes: Use 0.052 for hydrostatic/KMW calculations and 1029.4 for pipe and annular capacity calculations. Pump output is given in bbl/stk where required.

PART A - KNOWLEDGE & CONCEPTS

1. Which item provides primary well control during normal drilling operations?

A. The BOP stack

B. Hydrostatic pressure from the drilling fluid

C. The choke manifold

D. The mud-gas separator

2. Which action is an example of secondary well control?

A. Closing the BOP to contain an influx

B. Increasing trip speed

C. Reducing mud weight before a trip

D. Opening the well to the flowline

3. Why is early kick detection important?

A. It helps minimize influx size and the pressures required to control the well

B. It prevents all gas expansion

C. It eliminates the need for shut-in pressure readings

D. It guarantees the casing shoe will not fracture

4. As a gas kick is circulated upward correctly, what normally happens to the gas volume?

A. It decreases

B. It stays constant

C. It increases

D. It becomes zero at the casing shoe

5. While circulating, what effect does annular pressure loss have on bottomhole pressure compared with static hydrostatic pressure?

A. It always makes BHP zero

B. It has no effect

C. It makes BHP lower than hydrostatic

D. It adds pressure, making BHP greater than static hydrostatic

6. Why are two independent well barriers important?

A. They make calculations easier

B. They provide redundancy if one barrier fails

C. They eliminate the need for monitoring

D. They allow higher drilling rates

7. What is the main purpose of a flow check?

A. To calculate pump output

B. To test the accumulator

C. To determine whether the well is flowing

D. To measure annular capacity

8. A vertical surface-stack well is shut in on a gas kick with no float in the drillstring. Why is SICP commonly higher than SIDPP?

A. The drillpipe always has more friction

B. The casing gauge is calibrated higher

C. The drillpipe contains the lighter influx

D. The lower-density influx is in the annulus

9. What is MAASP primarily intended to protect?

A. The weakest exposed formation, commonly referenced at the casing shoe

B. The top drive motor

C. The trip tank

D. The standpipe manifold

10. What is the main objective of the first circulation of the Driller's Method?

A. Pump kill mud to the bit before circulating

B. Hold casing pressure at zero

C. Circulate the influx out using the original mud weight while maintaining well control

D. Increase mud weight while the influx remains on bottom

11. Which statement best describes the Wait and Weight Method?

A. Circulate the influx out first, then mix kill mud

B. Prepare kill mud and pump it during the first circulation while following the planned pressure schedule

C. Bullhead the influx back into the formation

D. Keep SIDPP constant after kill mud reaches the surface

12. Why is a slow pump rate used during a well kill?

A. It gives the choke operator time to react and manage pressure changes

B. It removes the need for a choke

C. It prevents any gas expansion

D. It keeps all surface pressures at zero

PART B - SCENARIOS & APPLICATION

Read each situation and choose the response that best matches the well-control principles taught in the workbook.

13. During a connection, the well continues to flow and the pit volume increases. After shut-in, positive SIDPP and SICP stabilize. What does this indicate?

A. Normal ballooning only

B. An influx has entered the well

C. The standpipe is draining

D. The trip tank is overfilled

14. A shut-in well has stabilized. Later, SIDPP and SICP begin increasing by approximately the same amount. What is the most likely concern?

A. Pump washout

B. Loss of hydrostatic due to heavier mud

C. Gas migration

D. A plugged choke

15. During a kill, pump speed must be changed. What pressure should be held constant while the pump rate is being changed?

A. Casing pressure

B. Drillpipe pressure

C. MAASP

D. Accumulator pressure

16. During Wait and Weight, kill mud has reached the bit. The pumps are shut down and SIDPP still shows pressure. Trapped pressure has been ruled out. What should be suspected?

A. The kill mud is definitely too heavy

B. The annular preventer is leaking

C. The casing gauge is always wrong at this point

D. The well may still be underbalanced or the stroke count may be incorrect

17. Total losses occur while drilling with water-based mud. Which response best matches the workbook approach?

A. Continue drilling and record the loss

B. Close the blind rams and immediately raise pump speed

C. Stop drilling, top-fill the annulus with water, and monitor the well

D. Open the choke fully and wait

18. During a kill, both drillpipe and casing pressures drop. With no system leak, the choke operator adjusts the choke to return pump pressure to the planned value. What happens to BHP?

A. It remains permanently low

B. It returns toward the correct controlled pressure

C. It must rise above fracture pressure

D. It becomes unrelated to choke position

19. The first circulation of the Driller's Method is complete and the well is shut down with no trapped pressure. What should SIDPP and SICP normally read?

A. Equal to each other and approximately equal to the original SIDPP

B. Both zero

C. SICP equal to the original SICP and SIDPP zero

D. SIDPP higher than SICP

20. A gas influx is entirely in the horizontal section of a well. The well is shut in and there is no float in the drillstring. What should SIDPP and SICP initially be?

A. SIDPP should be zero

B. SICP should be zero

C. They should be approximately equal

D. SICP must be twice SIDPP

PART C - CALCULATIONS

Work the problem before selecting an answer. Pay close attention to TVD, ID, OD, length, pump output, strokes, and pump speed.

21. Hydrostatic Pressure: Mud weight is 11.2 ppg and TVD is 9,500 ft. What is the approximate hydrostatic pressure?

A. 4,930 psi

B. 5,320 psi

C. 5,533 psi

D. 5,810 psi

Work: ____

22. Kill Mud Weight: Current mud weight is 10.4 ppg, SIDPP is 520 psi, and TVD is 10,000 ft. What is the approximate KMW?

A. 10.9 ppg

B. 11.4 ppg

C. 11.9 ppg

D. 12.4 ppg

Work: ____

PART C - CALCULATIONS (CONTINUED)

23. Initial Circulating Pressure: SIDPP is 450 psi and slow-circulating-rate pressure is 650 psi. What is ICP?

A. 1,100 psi

B. 650 psi

C. 450 psi

D. 200 psi

Work: ____

24. Final Circulating Pressure: SCRP is 650 psi, current mud weight is 10.4 ppg, and KMW is 11.4 ppg. What is the approximate FCP?

A. 593 psi

B. 650 psi

C. 680 psi

D. 713 psi

Work: ____

25. Pipe Capacity Using ID: Drillpipe is 5.000 in. OD with a 4.276 in. ID. The string length is 8,000 ft. What is the approximate internal pipe volume?

A. 114.8 bbl

B. 142.1 bbl

C. 165.3 bbl

D. 180.4 bbl

Work: ____

26. Annular Volume Using Hole ID and Pipe OD: Hole ID is 8.5 in., pipe OD is 5.0 in., and the interval is 2,500 ft. What is the approximate annular volume?

A. 83.6 bbl

B. 101.2 bbl

C. 114.8 bbl

D. 142.1 bbl

Work: ____

PART C - CALCULATIONS (CONTINUED)

27. Strokes to Bit: The drillstring volume is 142.1 bbl and pump output is 0.098 bbl/stk. Approximately how many strokes are required?

A. 1,450 strokes

B. 1,250 strokes

C. 1,650 strokes

D. 980 strokes

Work: ____

28. Circulation Time: Using 1,450 strokes at 30 spm, approximately how long will it take to pump that volume?

A. 36.7 min

B. 42.0 min

C. 45.0 min

D. 48.3 min

Work: ____

29. Tapered String Volume: The upper 6,000 ft of pipe has a 4.276 in. ID and the lower 3,000 ft has a 3.125 in. ID. What is the approximate total internal volume?

A. 118.0 bbl

B. 135.0 bbl

C. 149.5 bbl

D. 162.0 bbl

Work: ____

30. Pump Output and Time: Pump output is 0.121 bbl/stk, pump speed is 40 spm, and drillstring volume is 167 bbl. Approximately how long will it take to pump the drillstring volume?

A. 28.5 min

B. 31.2 min

C. 34.5 min

D. 39.0 min

Work: ____

SUPPLEMENTARY REVIEW - ANSWER KEY

Use this page after completing the review. Calculation answers show the rounded final result.

1. B	**11.** B	**21.** C - 5,533 psi
2. A	**12.** A	**22.** B - 11.4 ppg
3. A	**13.** B	**23.** A - 1,100 psi
4. C	**14.** C	**24.** D - 713 psi
5. D	**15.** A	**25.** B - 142.1 bbl
6. B	**16.** D	**26.** C - 114.8 bbl
7. C	**17.** C	**27.** A - 1,450 strokes
8. D	**18.** B	**28.** D - 48.3 min
9. A	**19.** A	**29.** B - 135.0 bbl
10. C	**20.** C	**30.** C - 34.5 min

Instructor note: Missed questions are review targets. Return to the related workbook section and work the concept again before moving on.