Equipment

**Learning Objectives**

- You will learn the basics of well control equipment including information on:
  - The BOP stack.
  - Associated equipment.
- Auxiliary equipment.
- What is needed and why.
- Operating characteristics.
- Maintenance and limitations.
Surface Equipment

Overview

- The Blowout Preventer (BOP) stack and related pressure control equipment are widely used throughout the exploration and production industry.
- Equipment is rugged and reliable when properly maintained.
  - Controls high formation pressure.
  - Allows passage of string and tools.
  - Provides for circulation.

- The BOP stack and equipment can work in pressures up to its rating.
  - As pressure ratings increase, tolerance to misuse decreases.
  - Equipment may be “de-rated” because of misuse, working in pressures over its pressure ratings, it's age and history.
BOP Stack

- API RP codes for blowout preventer arrangements are:
  - A = annular type blowout preventer.
  - G = rotating head.
  - R = single ram type preventer with one set of rams: pipe, blind or shear as operator prefers.
  - R_d = double ram type preventer with two sets of rams, positioned as operator prefers.
  - R_t = triple ram type preventer with three sets of rams, positioned as operator prefers.
  - C_r = remotely operated riser connector.
  - C_w = remotely operated connector attaching wellhead or preventers to each other.
  - S = spool with side outlet connections for choke and kill lines.
  - K = 1,000 psi rated working pressure.
Stack Arrangements

- Configuration issues for BOPs are complex. Type and arrangement depend on a variety of factors.
  - Maximum anticipated formation pressure
  - Types of formation fluids
  - Must be versatile
    - Close on pipe
    - Close on open hole
    - Provide circulating paths
    - Alternate circulating paths
  - Experience in area
  - Operator/Contractor:
    - Policy
    - Availability
  - Height
  - Weight, etc.
Stack Arrangements

- **Annular**
- **Ram**
- **Spool**
BOPs

Annular

Ram
Annular Type Preventer

- General
- Shaffer
- Rotating Heads
- Hydril
- Cameron
- Diverters
Annular Preventers – General Information

- Annular preventers are very versatile well-head pressure control devices.
  - Can seal on variety size pipe.
  - Can seal on wireline.
  - Can seal open hole.
  - Can be used as lubricating head for moving/stripping pipe under pressure.
Annular Preventers – General Information

- Parts of the preventer are:
  - Circular rubber packer element
  - Piston
  - Body
  - Head

- Hydraulic fluid is pumped into a closing chamber that forces the sealing element inwards.
  - The seal is typically obtained by vertical or horizontal packer movement.
Annular Preventers – General Information

- Operating pressures, characteristics, and limitations vary because there are many different models and manufacturers.
  - Because of these variations, hydraulic regulators should allow adjustment of operating pressure.
- The most recurring problem when using different makes and models is unfamiliarity of the operating pressures and closing pressures of the preventer.
Annular Preventers – General Information

- The larger the bore size and the smaller the pipe, the more the closing pressure that is necessary to provide a seal.
  - May require increased pressure to seal around irregular shaped objects (e.g., “square kelly”).
  - Increased pressure may lead to packer element deterioration.
Annular Preventers – General Information

- It takes a longer amount of time to close an annular than a ram type preventer because the annular requires more hydraulic fluid.
- Try to keep the operating pressures on the annular preventer as minimal as possible in order to preserve the life of the packer element.
Annular Preventers – General Information

- The regulator valve is crucial for moving or stripping pipe with tool joints. It maintains constant pressure and seals against the pipe.
  - Allows flow back through the regulator to maintain constant pressure.
  - *The drawback*: if well pressure becomes greater than manifold pressure and a seal fails, well pressure can enter through the closing line regulator back to the accumulator system.
- The factory may provide packer elements that are pre-split, which allow removal when the kelly or string cannot be removed from the well bore.
Annular Preventers – Hydril

MSP

- Large bore applications
- Low pressure usage
- Typically used as a diverter
Hydril GK Series

GK

• Widespread use, very popular.
  ▪ Available in 7 1/16 to 16 3/4 inch bore.
  ▪ Available up to 15K rating.
  ▪ Well energized – well bore pressure increases closing force on packer.
    – As well pressure increases, regulated closing pressure should be adjusted.
    – Consult Manufacturer for well pressure vs. regulated closing pressure chart.
Hydril GX Series

GX
- Designed for high pressure.
  - Available in 10 and 15K ratings.
  - Not as wellbore energized as GK.
Hydril GL Series

GL

- Developed for subsea BOP stack use.
  - Has balance chamber to compensate for mud in riser in water depth over 1,200 feet.
Annular Preventers - Shaffer

Spherical

- Widespread use, very popular.
  - Available in 4 1/16 to 30 inch bore.
  - Available 5 to 15K ratings.
  - 1,500 closing pressure, regulate after closing according to manufacturer.
Annular Preventers - Cameron

Model DL

- Widespread use, very popular.
  - Available in 7 1/16 to 21 1/4 inch bore.
  - Available 2 to 20K rating.
  - Operating system isolated from well pressure – well pressure does not alter its closing pressure.
Annular Preventers

Identify the following manufacturers!
Annular Preventers
Annular Preventers

- Suggestions to Improve Annular Preventer Operations:
  - Moving pipe through the preventer at high closing pressures causes wear and packer failure. Never use more regulated closing pressure than necessary.
  - Test packer when put in preventer.
  - Since there are various types of operating data for different makes of annular preventers, check the manufacturer’s manual for operating data.
  - Packers should be stored in cool, dry, and dark areas away from electric motors.
  - Keep pipe wet/lubricated when moving through closed preventer.
Diverter Systems

- The diverter system is used:
  - When only the conductor pipe is set and diverts flow and gas from the rig/work area.
  - When a well can’t be shut in because of a desire to prevent lost circulation or formation breakdown.
  - To divert gas from riser on subsea vessels.
Diverter Systems

- This system is made up of an annular preventer paired with a large diameter piping system underneath.

- Diverter systems are used to ensure safety of personnel and equipment from shallow gas flows.
  - Divers are made for short periods of high flow rate, not for high pressure.
  - Large diverter lines reduce erosion effects at high flow rates.
NOTE: When the diverter closes, the piston moves upward opening the flow path to the vent line while closing the flow path to the flow line.
Rotating Heads/BOPs

- The rotating head allows for string rotation with pressure below it.
  - Replacement packer elements should be kept on location while rotating pipes are under pressure in case of packer leak.
  - Sealing packer may fail at high pressures.

- Additional equipment may be required including:
  - Dedicated hydraulic unit.
  - Rig floor control panel.
  - Cooling systems.
Flow Tees/Crosses, Spacer/Spools

- Flow tees, sometimes called “Crosses” or “circulating spools” allows for the circulation of abrasive fluids through circulating ports without risking BOP damage.
  - Add height and weight to BOP stack.
- Spacers provide additional clearance for tool joint placement during stripping/snubbing operations.
- These should have a pressure equal to or greater than the BOPs in use.
Flow Tees/Crosses, Spacer/Spools
Rams

- Rams are the most basic and common BOP.
  - Rugged and reliable.
  - Available in many sizes, configurations and pressure ratings.
  - Custom built rams are used for special applications.
- Most ram models on surface BOP stacks can be manually closed in case of hydraulic system failure.
Rams

- The majority of ram models are designed to seal pressure from the bottom.
- A common problem occurs when changing packers on rams, which results in improper sealing of the bonnet or door seal.
- Most are designed to close with 1,500 psi regulated pressure.
18-3/4” Double U II Blowout Preventer
Ram Types

- Most common types of rams are:
  - Pipe.
    - Seals on only one size pipe.
  - Variable bore (VBR).
    - Seals on multiple or range of pipe sizes.
  - Blind rams.
    - Seals open well bore. Do not close on pipe or wire line.
  - Blind/shear rams.
    - Seals well bore after cutting action of its blades.
  - Shear (sometimes called “cutters”).
    - Cuts pipe.
    - Booster unit may be required to increase shear force.
Pipe Rams

- The pipe ram is the basic blowout preventer, designed to seal around the pipe.
  - The ram block cutout is the pipe ram’s strength and limitation.
  - The cutout is designed to provide a good seal around a specific diameter or size pipe.
- Pipe rams should not be closed on an open hole because damage and packer intrusion may occur.
Pipe Rams
Pipe Rams
Variable Bore Rams

- Variable bore rams seal on different sizes of pipe.
  - Used on wells with tapered strings and limited space.
  - These rams do not have to be changed when several diameter pipe strings will be used.
    - Can save a trip of the subsea blowout preventer stack.

- Variable bore ram (VBR) packers performed as well as pipe ram packers in standard fatigue tests.
Blind Rams

- Blind rams do not have pipe cutout on the ram block.
- These have bigger packing elements and are designed to seal without pipe in the bore.
- Blind rams should be pressure tested to rating.
- Should not be closed on tubulars and wire line.
Shear Rams

- Shear rams are designed for cutting tubular products.
- Shear rams need higher than normal regulated pressures and/or hydraulic boosters to generate shear force necessary.
- Packer element is small in shear rams.
Blind/Shear Rams

- Blind/shear rams have the combination of open hole closing ability and cutting ability.
- This allows the pipe to be cut and seals the wellbore after.
- Saves space, weight and height as you don’t have to have separate blind and shear rams.
Specialty Rams

When would the following rams be used?
Anti-Rotate Rams
There are several types of ram locking systems. Manual and Hydraulic systems available depending on ram manufacturer and model. Hydraulic ram locks engage and lock the ram position once actuated. Hydraulic opening pressure unlocks and opens the ram.
Sealing Elastomeric Components

- Packer elements of annular and ram preventers are made from a high tensile molded rubber and plastics compounds.
  - Natural rubbers, nitrile and neoprene are common compounds used for packer elements.
- Annular packer elements are shaped around a series of steel fingers, which add power and control the extrusion of packer material.
A codification system is used to identify different packer elements from each other by using information on its:

- Generic compound
- Date of manufacture
- Serial number
- Manufacturer’s part number
- Hardness
- Operating temperature range
Stack Installation

- New ring gaskets are always used when testing and installing BOPs.

- **CAUTION:** If the casing wellhead is not vertical, BOP and casing stress problems may develop.

- Use care when cleaning ring grooves, hydraulic ports, etc. This can help to eliminate future complications or testing problems of stack.
Flanges and Rings Gaskets

- Flanges and ring gaskets provide connection point and pressure seals between BOP stack components.

- Scratching ring-gaskets, ring grooves, or mating surfaces during cleaning or nipple up can ruin the pressure integrity of the stack, failure to pressure test and potential failure and loss of control during well control operations.

- Do not use wire brushes or scrapers on mating surfaces and ring grooves. Prevent any scratching that can cause failure.
Flanges and Rings Gaskets

- Carefully clean all ring grooves prior to installation.
- Rings should be closely examined for damage that may cause the ring to be unable to seat properly.
- Nuts on the connecting flanges must be properly tightened and kept tight at all times.
- “X” type ring gaskets should be used between BOP stack components.
There are several types of ring joint gaskets.

- The important thing to remember is that ring joints between BOPs cannot be reused as they are deformed when tightening to provide the primary seal.

Types include:

- API Type R Ring Joint Gasket:
  - Not energized by internal pressure.
  - May be octagonal or oval in cross section.
  - No face to face contact between the hubs or flanges.
  - Sealing occurs along small bands of contact between the grooves of the gasket on both the OD and ID of the gasket.
  - These small bands of contact may deform as a result of vibration and external loads. If the flange is not bolted in and tightened frequently, then the vibration or external loads may cause a leak to develop.
Common Ring Joint Gaskets

- **API Type RX Pressure Energized Ring Joint Gasket:**
  - Sealing occurs along small bands of contact between the grooves of the gasket and the OD of the gasket.
  - Gaskets are slightly larger than the groves and are compressed slightly to achieve sealing as the joint is tightened.
  - Loads are transmitted through the sealing surfaces but are prone to vibration and external loads.

- **API Face to Face Type RX Pressure Energized Ring Joint Gasket:**
  - Sealing occurs between the bands of contact and the OD of the gasket.
  - Once compressed and tightened it cannot be reused as it plastically deforms once the initial seal occurs.

- **Cameron Face to Face Type RX Pressure Energized Ring Joint Groove**
  - A modification to the RX Ring with closer tolerances minimizing plastic buckling effects.
Common Ring Joint Gaskets

- API Type BX Pressure-Energized Ring Joint Gasket:
  - Sealing occurs along small bands of contact between the grooves of the gasket and the OD of the gasket. Face to face contact is achieved by high compression.
    - Compression energizes the ring.
    - The ring is plastically deformed and will not provide the same degree of sealing if reused. DO NOT REUSE “X” type rings.
  - Loads are transmitted through the sealing surfaces but are prone to vibration and external loads.
    - Often axial holes are pre-drilled in the ring to ensure pressure balance and proper contact.

- Cameron Type AX & Vetco Type VX:
  - Pressure-energized.
  - Sealing along OD of gasket and grooves.
  - Load is on collet connector and not on ring.

- Cameron Type CX Pressure-Energized Ring Joint Gasket:
  - Patterned after the AX but is recessed to prevent contact damage.
Minimizing BOP Wear

- In order to minimize friction and wear, the pipe should drop down the center of the BOP without coming in contact with its walls.
  - This can be difficult because the BOP stack may be off-centered with any movement, settling, or tipping of the rig.
  - The BOP may also be off-centered if the derrick is not perpendicular at the base, causing the top to be off-centered from the hole.
  - BOP wear is not immediately apparent.
  - The casing and wellhead may also be damaged.
- There is a chance that this damage can increase with time and may result in the stack not being able to seal during a kick.
  - Wear rings or bushings reduce inside wear and damage.
BOP Test Tool

- The BOP test tool is a device attached to the end of tubing and run to the bottom of the BOP stack or in the casing head.

- It is fitted with several sealing elements.
  - These elastomeric seals should be inspected prior to use and replaced when necessary.
    - If these fail the well bore may become pressurized.
Choke/Kill Line Connections

- Choke/Kill line connections are potential weak points.
  - Essential that these points are frequently checked.
- Common problems:
  - Dirty seal rings.
  - Loose nuts.
  - Using nipples that are too light.
  - Damaged mating surfaces.
  - Long unsupported nipples or lengths of pipe.
  - Use of pressure hoses.
- Bends in the pipe, or the combination of bent lines and high-pressure and high flows can lead to erosion.
Choke/Kill Line Connections
Safety Valves/Floats/BPV

- General
- FOSV
- Upper Kelly Cock
- IBOP
- Lower Kelly Cock
- BPV
- Float Sub/Dart Valve
Safety Valves and Floats

- Safety valves, floats, and blowout preventers close off tubing/drill pipe.
- Many types of these are handled and often made up by the crew. This requires training of the crew on proper use and maintenance. Types include:
  - Upper kelly cock.
  - Lower kelly cock.
  - Full Opening Safety Valves (FOSV).
  - Inside BOP.
  - Floats/back-pressure valves (BPV)/check valves.
Upper Kelly Cock

- The upper kelly cock protects the kelly hose, swivel and surface equipment from high well pressure.
  - Closes with wrench.
  - Wrench must be kept on rig floor.
  - May be remotely actuated in some systems.
- The upper kelly cock must be pressure tested when the stack is tested.
Lower Kelly Cock

- The lower kelly cock allows removal of kelly with pressure in the string.
- It should not be used as a fluid or mud saver valve.
  - It must seal on pressure and too much use can wear sealing elements.
  - Galling of the lower kelly cock can occur from continual makeup and breakout.
    - Galling can be prevented by using a saver sub.
    - Inspections should be made to notice if galling is occurring.
- Closing wrench should be kept on rig floor at all times.
Full Opening Safety Valves

- The **Full Opening Safety Valve** (FOSV) is the first “stabbing valve” that should be installed as soon as a kick occurs.
  - It must be kept in the immediate work area and handy at all times.
  - It must be kept in the open position.
  - The wrench to close it must be in the immediate work area and easily found.
Full Opening Safety Valves

- Stabbing valves need little maintenance but needs to be operated weekly to prevent it from freezing up.
- It should be tested when BOPs are tested.
- Stabbing valves should be light enough for the crew to maneuver.
Inside Blowout Preventer

- The **Inside BlowOut Preventer (IBOP)** sometimes called the Gray valve is a one way, or check valve.
- It is used for stripping in the hole under pressure.
  - Allows the hole to be circulated but prevents pressure or flow reversing back into the string.
- Since it is not full-opening, the inner diameter of the string is restricted.
  - Does not allow wireline tools to be run through it.
  - For this reason, it is rarely used unless necessary.
- Typically an actuating rod assembly is used to keep it in the open position. By removing the rod assembly, the valve should close.
Back-Pressure Valves (BPV)

- **Back-Pressure Valves (BPV)** have many uses:
  - Stripping, snubbing, and pressure work.
  - Drilling operations to prevent well from U-tubing.
  - Preventing cuttings from clogging bit, motors and logging tools.

- Most common types are:
  - Spring operated (not full opening and will restrict tools from running past it)
  - Flapper

- Both types are latch-open models that can be run in the hole with the valve in the open position.
Back-Pressure Valves (BPV)
Back-Pressure Valves (BPV)
Float Subs/Dart Valves

- Depending on the operation a sub may be run that will accept a valve pumped to the sub.
  - FOSV stabbed first, then dart loaded into a make-up joint (or into the IBOP if possible).
  - Chicksan lines made up to IBOP.
  - FOSV opened and dart pumped to float sub.
- Float subs are subject to erosion and the dart may not seat properly.
Chokes and Manifolds

- Choke/Kill Manifold
- Chokes
- Gate Valves
- Remote Choke Console
- Manual Adjustable
- Remote Adjustable
Choke/Kill Manifold

- Choke/Kill manifold provides:
  - Routing of fluids from the well to various paths. These paths include:
    - Pits
    - Degasser
    - Bleed/vent line
    - Flare line
  - A method of circulating from the BOP stack under a controlled pressure.
  - Alternate paths so that chokes and valves can be fixed or replaced.
**Recommended Practices for Planning and Installation of Choke Manifold**

- All manifold equipment that may be affected by pressure should be tested upon installation. This must be done in order to ensure that it’s working pressures are at least equal to the rated working pressure of the blowout preventers.
- All components must meet API specifications for pressure, corrosiveness, abrasiveness, temperature of the formation and drilling fluids in use. A back-up valve should also be installed after each primary valve in case of primary valve failure.
- For pressures greater than 3M only flanged, welded or clamped connections should be used.
- Manifold should be in a readily accessible location, preferably outside the rig’s substructure.
- Lines should be straight as possible, anchored to prevent whip or vibration, of size to prevent excessive friction or erosion. Practically, these lines should be at least 3” ID and rated to at least BOP ratings. For air/gas operations consider at least 4” lines.
- Alternate flow routes should be provided to ensure continuous operations if primary line(s) become plugged or eroded.
- Both high and low temperature properties of the manifold should be taken into account.
- Bleed, straight through lines should be of size to minimize pressure to system and to allow pressure bleed off with preventers closed.
- Gauges suitable to fluid operations should be installed to monitor pressure.
- Remote actuated valves for operations over 5M as well as a backup system should be installed.
- All manifold components should be H₂S rated.
Chokes

- Chokes control the flow rate of fluids and provide back-pressure during well control operations.
  - Back-pressure is an increase in friction by restricting flow through an orifice.
- There are several types of Chokes.
  - Fixed
  - Adjustable:
    - Manual
    - Remote actuated
Chokes

- Fixed chokes, such as a production choke are not suitable for well control as the orifice size cannot be adjusted quickly.
- Most kill operations use remote adjustable choke.
Adjustable Chokes

- Both, manual and remote chokes, are used to adjust the orifice size to regulate flow and back-pressure.
  - The remote actuated choke consists of operating consoles that include:
    - Choke position.
    - Stand pipe and casing pressure gauges.
    - Stroke and/or volume counters.
    - A positioning valve.
    - A pump for hydraulic operation
    - An “on” and “off” switch.
  - Both chokes are capable for well killing operations, but they are not often used, which allows them to freeze up frequently.
Remote Choke Consoles
Remote Choke Consoles
Manual Adjustable Chokes

- Consists of a tapered bar and seat.
  - As the bar approaches the seating area, there is minimal clearance and additional restriction for fluid going through it, which produce more back-pressure on the well.
- May be primary choke, depending on equipment available, or a back-up to remote adjustable.
- Excellent for use in stripping operations.
  - This piece should be frequently tested and lubricated.
Remote Adjustable Chokes

- Consists of a bar that moves in and out of a narrow choke gate, or “half moon opening” fixed and rotating plates.
- It operates by the choke console, which releases hydraulic pressure on a double-acting cylinder that in turn rotates the upper choke plate or bar to a more open or closed orifice size.
- In drilling operations and pressure-related work, these are preferred because they allow for monitoring of pressures and strokes and control the position of the choke all from one console.
- May be trimmed for H2S service.
Closing/Accumulator Systems

- A manual screw-jack system was used to close ram preventers prior to the 1950s. This system is still in use in some areas.
- Since it is important to shut the well in quickly, hydraulic closing units were developed.
- An accumulator must be reliable when it comes time to shut in the well during a kick.
  - Hydraulic closing systems have extra pumps, excess fluid volume, and backup systems.
Closing/Accumulator Systems
Good Practice or Bad?
Good Practice or Bad?
Closing/Accumulator Systems

- Maintenance on the accumulator system should be performed at least every month and should include:
  - Cleaning and washing of air strainer.
  - Fill air lubricator.
  - Check air pump packing so it is loose enough that the rod is lubricated, but not so loose to allow dripping.
  - Inspect electric pump packing.
  - Clean suction strainers.
  - Make sure chain drive on electric pump is full of chain oil.
  - Make sure fluid volume in hydraulic reservoir is at operating level.
  - Clean high-pressure hydraulic strainers.
  - Lubricate four-way valves.
  - Clean air filter on regulator line.
  - Check Precharge of accumulator bottles.
Closing/Accumulator Systems
Closing/Accumulator Systems
Closing/Accumulator Systems
The Nitrogen Pre-charge

- Most liquids are generally not compressible. So, a gas filled bladder is used inside accumulator bottles to push out closing fluid to the BOP. Bottles must be kept near 1,000 psi pre-charge operating pressure.
- No additional fluid pressure can be stored if nitrogen precharge bottles lose their charge.
- Bottles should be checked for proper pressures using the following procedure:
  - Shut off air to the pumps and power to the electric pump.
  - Close the accumulator shut-off valve.
The Nitrogen Pre-charge

- Open the bleeder valve and bleed the fluid back into the main reservoir.
- The bleeder valve should remain open until the pre-charge is checked.
- Remove guard from accumulator bottle pre-charge valve. Screw on gauge assembly. Open accumulator pre-charge valve by screwing down on the T handle. Check Pre-charge pressure. Gauge should read 1,000 psi or close to it. If over 1,100 psi, bleed excess pressure off; if under 900 psi, recharge to proper pressure with nitrogen. Close Pre-charge valve by unscrewing T bar, remove gauge assembly. Reattach guard.
- Open accumulator shut-off valve.
- Turn on air and power. The unit should recharge automatically.
The Nitrogen Pre-charge

Manifold

N₂

3000

2200

1000
Accumulator Charging Fluids

- Fluid used in the accumulator system should meet the following requirements:
  - Non-corrosive, non-foaming lubricant
  - Fire proof
  - Weather proof
  - Not make rubber sealing brittle
Accumulator Charging Fluids

- Hydraulic oil or a mixture of fresh water and soluble oil are ideal fluids for these conditions.
  - Hydraulic oil is more expensive and considered a pollutant, whereas, fresh water and soluble oil is not.
- Improper and corrosive fluids can harm accumulator and closing elements of BOP stack.
Volume Requirements

- The accumulator system should contain an adequate supply of useable fluid to function BOPs.
- API requires a minimum of 1.5 times the volume to close all BOP’s, however; more conservative requirements utilize 3X the volume to close all BOP’s.
  - This ensures the ability to close everything and still have the pre-charge remaining.
- Tables are available to look up volume requirements based on pre-charge and accumulator bottle size.
- Can also be calculated.
Accumulator Volume Calculation

- Since a pressurized bladder will occupy space in an accumulator, the actual amount of “useable fluid” must be calculated.

  \[ V_u = V_S \times (P_p + A_p) \times (A_p / R_p - 1) \]

  Where:
  - \( V_u \) = useable volume of fluid, gal.
  - \( V_S \) = volume of fluid in the system, gal.
  - \( P_p \) = pre-charge pressure, psi.
  - \( A_p \) = total accumulator pressure, psi.
  - \( R_p \) = required pressure to close preventer, psi.

- \( V_u \) should be greater than the totaled volume to close all accumulator functions multiplied by the appropriate safety factor. Volumes to close each BOP stack component may be looked up in common tables, operating manuals, and from the manufacturer.

- For subsea systems, the water depth’s hydrostatic pressure should be added to \( V_S, P_p, A_p \) and \( R_p \). This volume changes from location to location as water depth varies.
Fill-Up Line

• Fill-Up lines are used to fill the hole during trips and when the well is not circulated.
• If fluid is left in the fill-up line it can plug. Corrosive fluids may damage the line.
• Volume used to keep the hole full should be closely monitored, measured and recorded during trips and while out the hole. It is recommended that a small volume tank be used for fill measurements.
Gas Handling Equipment

- Well control operations are difficult and potentially dangerous without gas handling equipment.
- Gas handling equipment allows venting and/or burning of large amounts of gas that is a potentially explosive mixture if allowed to mix with air surrounding the rig.
- If this system is overloaded, flammable/toxic gases may accumulate around the pit and rig floor areas. The pump rate must be reduced or stopped.
Mud Gas Separators (Gas Busters)

- The Mud Gas Separator (MGS) is the primary method of handling gases circulated through the choke manifold.
- Diverts gas/air mixtures from work areas.
- The gas separator is more efficient with clear, low-viscosity fluids that allow gas to break out of the fluid.
- A gas separator may not be sufficient for thicker fluids.
- Pressure inside the gas separator should be watched carefully.
Mud Gas Separators (Gas Busters)
Degassers

- Degassers are used to remove gases from the circulating fluids.
- Since thick fluids will not allow gas to break free, degassers separate the gas from the fluid using a vacuum chamber, a pressurized chamber, a centrifugal spray, or a combination of these.
  - A vacuum tank or pump sprayer is the most common degasser.
    - Vacuum degassers are generally more effective when operating with heavy viscous muds and when it is difficult to extract the gas.
  - As mud viscosity and gel strengths increase, so do degassing time and extraction energy requirements.
Degassers
Circulating System

The circulating system consists of the following components:

• Pumps
• Surface lines
• Standpipe
• Kelly/top drive
• Kelly hose
• Swivel
• Workstring
• Well annulus
• Shale shaker
• Fluid tanks
• Associated circulating manifolds
Pumps

- Fluid is moved through the circulating system by positive displacement pumps.
  - Since triplex pumps smoothly displace high volumes, they are more commonly used versus duplex pumps.
- Rig pumps are generally equipped with at least one stroke counter to accurately measure displacement of volume.
Pumps

- If pump operations exceed pressure restrictions, the pump’s pressure relief valve will blow and cause the well to unload into the pits.
  - Some operations require the use of higher pressure/low volume service company pumps.
- Proper maintenance should be used to ensure safe operations and accurate displacements.
- Proper alignment should be checked prior to any pump startup.
Pumps
Circulating Manifold System

- The circulating or “standpipe” manifold system allows pump selection, fluid routing, and isolation of pumps not in use.
- It routes fluid from the pumps to the upper area of the derrick to connect with the rotary, or kelly hose.
  - The kelly hose provides a flexible connection between the standpipe and swivel and allows for pipe travel while pumping.
  - The swivel provides for rotation of pipe while pumping.
- Changes to manifold lineup:
  - Only if another fluid flow path has been opened first.
  - The entire manifold system should be frequently checked for correct alignment.
Shale Shakers
The mud/fluid return indicator is one of the most important tools used in kick detection.

Detection of change is crucial because if the mud return indicator dictates a change from an established trend, a kick or lost circulation may be occurring.

The flow sensor should be frequently checked to see if it is working properly by changing pump rate to see if the flow sensor report changes.
Mixing Facilities

- Most operations require good mixing facilities.
  - A circulating pump and lines are used whenever chemicals have to be mixed on site, fluids have to be weighted or conditioned, or if the fluid has to be kept moving.
- Fluids and chemicals are generally mixed by centrifugal or impeller pumps that are lined up through a jet and hopper system.
  - The mixing pump discharges fluid at the top of the tank or through jet guns.
- Oxygen scavengers are often used because discharge lines and jet guns aerate fluid in the tank.
Mud Pits / Trip Tank
Pits or Tanks

- Several interconnected tanks are used to hold, treat or mix fluid for circulating or storage.
- The proper amount of tanks and volume capacity should be available depending upon the operation.
- Fluid can be routed tank to tank by:
  - Ditches interconnecting tanks.
  - Equalizing lines from tank to tank.
  - Using circulating/mixing manifolds.
- In an interconnected pit system, the first tank is usually a settlement tank that prevents sand or unwanted solids from entering the main mixing, circulating suction tanks.
- The intake and discharge lines from the degasser should be in separate pits.
Pit Volume Totalizer

- PVTs monitor, record, and total up the volume in each pit as well as the total surface fluid volume.
- The pit volume indicator is a warning instrument for kick detection.
  - When a well kick pushes fluid out of the hole, there is an increase in pit level volume that is recorded by the PVT; therefore, an increase in pit volume is a positive sign of an influx.
- These systems use mechanical floats or electrical sensors to measure the height of fluid.
Trip Fluid Volume Measuring Device

- The combination flowline sensor/pump stroke counter measures the mud required to fill the hole on a trip.
- Pump strokes are tallied by the counter, which automatically shuts off when the flow-line sensor shows flow at the flow line.
- The amount of calculated pump strokes needed to fill the hole per stand of pipe is compared to the pump strokes actually required to fill the hole.
- Generally, pump strokes are kept on total strokes to fill the hole and strokes to fill the last fill-up.
- **Maintenance**: Floorhand must check hole during first fill-up to be sure pump stroke counter shuts off when flow starts.
  - Often, the switch mounted on the pump was removed during repairs and was never replaced.
The trip tank is the best method of measuring the amount of fluid needed to fill the hole on a trip out or the amount of fluid displaced on the trip back in.

- A small tank with accurate measuring markers provides more precise measurement.

Measuring the amount of fluid required to fill or that is displaced from the well is necessary to ensure that a kick has not entered the well.

There are several different types of trip tanks:

- An automated trip tank has a pump, actuated by the driller that uses the flow line sensor to indicate when the hole is full.
- Continuous fill trip tanks fill the hole automatically as pipe is pulled by circulating from the tank across the hole.
Trip Tank
Trip Tank

- If the tank is used to measure displacement from pipe on trip in, it is generally positioned below the flow line level.

Maintenance of Trip Tanks:

- Check valves for easy operations.
- Clean trip tank markers and pit level floats of fluid buildup or solids.
- Calculate and post accurate volume displacements.
- Check driller’s recorder for accuracy.
Maintenance of Pit Volume Totalizer:

- Check chart paper and ink.
- Clean off mud accumulations and ensure easy movement of any/all floats.
- Move the float up and down to make sure that these changes are reported to the driller.
- If the system is air (pneumatically) operated, bleed off water from the air dryer.
  - Check for oil in the air lubricator.
- If using sonic sensors, check that the sensor is free of mud accumulations and that the fluid does not have foam floating on top.
Gas Detectors

- Gas detectors detect changes in gas flow out of the well and areas of gas concentration in places that must be monitored for explosive or hazardous gas presence.
  - Special gas detectors are used in areas containing toxic gases that can harm personnel.
- Frequent testing of gas detectors should be performed.
- Stale or trapped gas in gas detectors can be removed by blowing intake/sniffing lines.
- Broken and plugged lines or dirty detector heads are noticeable problems with gas detectors.
Pressure Gauges

- Pump, choke, and shut-in pressures are crucial to well control operations.
- Drill pipe or tubing gauges are generally located on the driller’s console and the remote choke panel.
- Choke pressure gauges are located on the choke/kill manifold and remote choke panel.
- The gauge at the remote choke panel is used when recording slow pump rates.
- Gauges should be repaired when there are unusual and large discrepancies between readings.
  - Small inaccuracies can be tolerated if conditions do not worsen and if the inaccuracy is over the pressure range of the gauge.
Pressure Gauges

- Most regulatory bodies require a pressure gauge to monitor pressure between strings of casing.
- There is debate over low pressure accuracy of large range gauges.
  - For this reason, many rigs use multiple gauges in order to compensate for the inaccuracies.
- When objects hit the gauge, vibrations, pulsation, and shock absorption may cause inaccuracy and damage.
  - Fluid-filled gauges provide a type of cushion from vibrations and shocks and also lubricate and protect internal components.
- A cause of inaccuracy is air in the hydraulic line from the gauge to sensor, so a hydraulic fluid hand pump can be used to purge the lines.
Gauge/Atmospheric Pressure

- A gauge placed at the bottom of a fluid column not only reads the hydrostatic pressure of the column, but it also reads the atmospheric pressure exerted on that column.

- Atmospheric pressure at sea level is about 15 psi but fluctuates depending on different weather conditions and elevation.

- A gauge that reads in \textit{psig} has been adjusted to subtract the atmospheric column above it.
Gauge/Atmospheric Pressure

- Flow Line Sensor (surface stacks):
  - Set high/low sensor to the desired amount of flow variance.
  - Turn on audio and visual alarms.
  - Manually pull up and push down on the flow line sensor to ensure that equipment is properly working.

- Flow Line Sensor (subsea stacks):
  - Set high/low sensor to the desired amount of flow variance.
  - Turn on audio and visual alarms.
  - Manually pull up and push down on the flow line sensor to ensure that equipment is properly working.
• Standard geological graphs are commonly used to record measurements of time, depth, weight, torque, pressure, and penetration at one foot intervals.
• In addition, some systems also accurately display the rate of penetration in feet-per-hour.
• More advanced systems may include trend settings and alarms.
• Maintain according the manufacturer’s recommendations.
| WILD WELL CONTROL | Information Systems |

<table>
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<tr>
<th>DEPTH</th>
<th>HOOK LOAD</th>
<th>PUMP RATE #1</th>
<th>PIT VOLUME</th>
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Information Systems
Rotating Systems

• Most operations require the use of string rotation at one point or another.
  • A rotary table transmits the pipe rotation and supports the Workstring when the load is not supported by the derrick.
  • Pipe rotation can also be rotated by a top drive, power swivel or power tongs.
• Changes in the rotational torque indicate down hole problems.
Top Drive
Equipment

Learning Objectives

- You learned the basics of well control equipment and gained knowledge on:
  - The BOP stack
  - Associated equipment
- Auxiliary equipment
- What is needed and why
- Operating characteristics
- Maintenance and limitations
<table>
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<tr>
<th>Flex Rig 1</th>
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<tbody>
<tr>
<td>Cameron BOP Stack</td>
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<td>1. Annular BOP</td>
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<td>3. Drill Spool</td>
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<td>4. Manual and Hydraulic Gate Valve, Check Valve</td>
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<td>5. Single Ram-Type BOP</td>
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<td>6. Casing Head</td>
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<td>8. Pressure Gauge</td>
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<td>9. Manual Gate Valve</td>
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<td>10. Hydraulic Gate Valve</td>
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<td>11. Drilling Choke</td>
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<td>17. Mud Pumps and Manifold Pressure Gauges</td>
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