# *Well Control*

## Preview

*This topic discusses the causes of a kick, methods of kick detection, well control procedures, and the components and function of surface and subsea well control equipment.*

## Kick Causes

A kick is the term used to describe the inflow of formation fluid into the wellbore during a drilling operation. This mainly arises due to the formation pore pressure being greater than the hydrostatic pressure imposed by the mud column. This can happen in a normally or abnormally geopressured formation.

A kick may be composed of water (usually salt water), oil, natural gas or a combination of these fluids. The influx of formation fluid may arise for a variety of reasons. The four main causes are:

- Insufficient mud weight
- Not keeping the hole full
- Swabbing
- Loss of circulation (partial or complete).

Kicks generally occur during trips, with influx occurring from a combination of the effects of swabbing and failure to keep the hole full. Swabbing is primarily the result of the viscous drag between the upward-moving drill stem and the downward-moving mud. The latter is moving downwards to replace the volume of drill-stem equipment removed from the hole (the open-end displacement). The faster the pipe is moved, the greater this viscous drag becomes, hence the greater the reduction in annulus pressure.

There is also the 'piston effect' of the bit and stabilisers, if they are 'balled-up' with mud and clay. **It must be realised that this is not, normally, the primary cause of swabbing.**

Kicks occur during drilling operations most often because of insufficient mud weight.

### Insufficient Mud Weight

Insufficient mud weight may occur due to:

- Penetration of an abnormal pressure zone.
- Accidental dilution of the mud by fluid addition at surface. (This occurs more often than it should. Usually a water valve is left open during a period of fast drilling through clay-rich formations and gets forgotten.)
- Dilution of mud by influx from an aquifer exposed to open hole.
- Gradual mud density reduction due to gas cut and failure to degas the mud at surface.
- Improper mud mixing and poor quality control in measurement.

For strategic operational reasons, a borehole may be drilled underbalanced with a controlled kick (i.e. continuous production) taking place. This requires specialised systems and equipment and is beyond the scope of this present module.

## Low Level of Drilling Fluid Column

Two conditions may lower the fluid column in the annulus. These are:

- Failure to keep the hole full during a trip
- Lost circulation during drilling.

In pulling out the drill stem, the driller must refill the hole with mud of equivalent volume. Monitoring the volume of mud filling the hole is done with the use of the Trip Tank. (This may be known as the "Possum belly" on some rigs. Unfortunately, this term is used to refer to different things on different rigs, so avoid it.)

The trip tank is a small mud tank (approx. 50bbls) separate from the active pits. This trip tank is equipped with a volume gauge that can be monitored from the rig floor and/or mud loggers' console. In monitoring the trip, the driller must calculate the theoretical mud volume displaced by one or five stands of drill pipe. During the trip, the driller then measures the actual mud volume pumped into the hole for each stand of pipe pulled.

Lost circulation is the loss of substantial quantity or whole mud into the formation. It may occur as a result of:

- Mud loss to a porous, cavernous or vuggy formation
- Penetration of depleted or subnormal zones
- Mud loss to fractures opened by excessive annulus pressure. This may be due to annular blockage, surge pressures, excessive hydraulics, pressures imposed to break mud gel strength.

Lost circulation will result in insufficient mud column and thus reduction in bottom-hole pressure. A kick due to lost circulation can be a major well control problem. When the well is shut in, an underground blow-out can occur, where the high-pressure formation 'supercharges' the lower pressure formation. This has been known to cause contamination of aquifers and other regrettable problems.

## Excessive Swabbing

As noted earlier, swabbing is the reduction of bottom hole pressure caused by upward pipe movement. As the pipe is being pulled out during trips, mud flows down through the annulus to replace the volume of drilling tools removed from the hole. There is, thus, viscous drag between upward-moving drill stem and the mud, and between the downward mud flow and the casing/hole. This causes a frictional pressure loss in the direction of the surface. The result is reduced bottom hole pressure. The higher the trip speed, the worse this effect. The swab pressure depends on:

- Pipe velocity
- Bit and/or BHA 'balling'

- Clearance between pipe and hole - the smaller the annular cross section, the greater the swabbing action
- Mud rheology - the higher the viscosity, the greater the swabbing action.

### Excessive Drilling Rate in Gas-Bearing Formations

The densities of formation fluids (gas, oil or water) are much lower than that of conventional drilling fluids. Any influx of formation fluid therefore reduces the mud density in the annulus. This influx, otherwise known as mud cut, is measured using sensors that measure mud density and conductivity at injection and at flow line.

Mud cut may occur from:

- Influx due to inadequate mud weight or swabbing
- Diffusion of fluid into the hole due to the pressure in the annulus being lower than the pore pressure
- Air entrained in mud during trips (the so-called 'kelly air')
- Expansion of drilled gas as it reaches the surface.

The majority of such kick problems arise from the reduction of mud weight due to the expansion of drilled gas, especially in large diameter holes, such as surface holes drilled at high rates. For such holes drilled without a blowout preventer in place, a small reduction in mud weight can lead to a violent kick and with the loss of primary control, lead to a blowout.

## Kick Detection

A kick can occur at any time while drilling a well. To prevent any major catastrophe, early kick detection is essential for proper well control. As a primary precaution, it is important for all personnel, including the mud logger, to be in a state of readiness. Certain pre-kick information must be collected and available for use in case a kick occurs. These include volumes and pressures data. **A Kick Control Work Sheet** (see Appendix) must be maintained for this purpose.

# Pre-kick data requirements are as follows:

## Maximum Working Casing Pressure

The casing and blowout preventer (BOP) are designed for the different expected pressures during each drilling phase. This is determined during well planning and is generally the maximum pressure rating of the BOP and its outlets or 80% of the burst pressure of the last casing. The 80% consideration is a safety factor for the casing string.

## Maximum Allowable Annulus Surface Pressure (MAASP)

This is the annulus pressure at the surface that corresponds to the pressure at the weakest point of the hole. Fracture gradient at the last casing shoe usually defines the weakest point. However; for some boreholes, the MAASP can be the casing burst pressure or BOP rupture pressure if they are less than the fracture gradient (this is poor well design) or a permeable or weaker formation in the open hole. The MAASP represents the maximum annulus pressure that can be tolerated without risking losses while controlling a kick. The MAASP is estimated from the following equation:

**Equation 1**

$$MAASP = 0.052 \times (Frac - \rho) \times D_w$$

Frac = Fracture pressure at shoe given as equivalent mud weight in ppg.

$\rho$ = Current mud density, ppg

$D_w$ = True Vertical Depth (TVD) of weakest point, ft

## Rig Capacity for Weighting Mud

Although this data does not appear in the well-kill worksheet, it is important, as it defines the number of circulation cycles necessary to regain primary control with the given change of mud. The rig capacity depends on total reserves of weighting materials (Barites, etc) and the maximum rate of addition to system. The maximum rate of addition is measured in lb/min or kg/min. Backup supply MUST always be available on the rig.

## System Pressure Losses (SPL) at Slow Pump Rate SPR (or Slow Circulation Rate - SCR)

Circulation at the normal pump rate for drilling may produce surface pressures greater than the MAASP. We use a slow pump rate to kill the well partly for this reason, but also because it gives us more time to think, to observe what is happening and to DO THE JOB CAREFULLY. Therefore a System Pressure Loss at Slow Pump Rate (SPR, or SCR – Slow Circulation Rate) for kick control must be determined at regular intervals. This is usually 20 or 30 strokes per minute for a large triplex pump.

This slow rate must be taken:

- At the start of each tour
- If the mud weight changes
- If bit configuration changes (e.g. a nozzle becomes plugged)
- After bit and/or BHA changes.

If a kick occurs, the influx will be circulated out at the predetermined slow circulation rate. This is called the kill rate. The pressure losses must always include the choke line pressure losses, especially offshore, with a subsea BOP, where this could be substantial.

## Pump, String, and Hole Configuration

This includes the data used for the determination of the lag time (surface to bit and bit to surface) and contains:

- Pump capacity
- Hole size
- Drill string capacity (internal volume)
- BHA capacity
- Annular capacity (bit to casing shoe and casing shoe to BOP)
- Casing data (size, weight, burst pressure, shoe depth)
- The worksheet includes the space to fill in lag time in strokes or minutes for the proposed kill rate.

This estimation is usually computerised and continuously logged. IT IS IMPORTANT THAT YOU KNOW HOW TO CALCULATE THESE THINGS WITHOUT A COMPUTER.

# Kick Detection Techniques

There are a number of indicators that provide early warning of kick occurrence. Positive kick indicators are:

- Mud pit level/flow increase
- Incorrect hole fill up during trip
- Decrease in standpipe pressure/increase in pump rate
- Increase/decrease in drill stem weight.

Potential indicators are:

- Increase in penetration rate;
- Lost circulation;
- Changes in gas levels, mud density and mud conductivity.

Parameters used for detecting abnormal pressure zones are also potential kick indicators. These include:

- Torque, overpull and drag;
- Shale caving increase;
- Shale density/shale factor changes;
- Flowline mud temperature changes;
- ‘d’ Exponent changes.

The surest indicators of a kick occurring are **Mud Pit Level Increase and Flow Increase together.**

These parameters are major positive indicators. As the influx of formation fluid displaces the mud in the annulus, the pit level would increase in the active mud tanks. There would also be evidence of increase in return flow rate (if logged, which it should be).

The effectiveness of pit gain/flow increase depends on:

- Initial size and type of kick
- Mud fluid base and rheology
- Minimum sensitivity of the measuring systems.

A gas kick is more difficult to handle than oil and/or water due to its compressibility. It may tend to go into solution in the drilling fluid, particularly in oil based muds, only coming out of solution very near the surface.

A small gas kick can expand to many times its original volume by the time it reaches the surface. Return flow is a more sensitive indicator of a kick than pit level monitoring and, crucially, can permit detection of the presence of an influx earlier than pit level. The return flow sensors may, therefore, provide the first warning of a gas kick. Sensor resolution and crew alertness determine the minimum size of kick detected.

The driller and mud logger should normally set alarms on the flow indicator and pit volume parameters close to the actual pit value. Reports should be sent to the driller no matter how small the pit gain is. Daily checks on the alarms and routine maintenance are essential to effective monitoring.

## Incorrect Fill-up During Trips

When pulling out of the hole, if the volume of mud pumped to keep the hole full is less than that normally required, then there is an evidence of influx. The mud volume required should be equal to or slightly greater than the displacement of the drill pipe (normally five stands) pulled. Mud loggers and drilling engineers MUST follow trips even though an automatic trip monitor is usually used.

Conversely during a trip into the hole, the downward movement of the drill pipe expels fluid from the annulus to the trip tank or active mud system. This return flow should cease a few seconds after pipe movement stops. If flow continues, then there is may be a kick.

## Decrease in Standpipe Pressure/Increase in Pump Rate

As indicated in the U-tube analogy, influx of fluid into the annulus creates an imbalance resulting in a decrease in hydrostatic pressure in the annulus. In such an unbalanced system, gravity helps move drilling fluid down the hole, requiring less energy from the pump. This will result in a decrease in the standpipe pressure.

This is not the only reason that there may be an increase in pump rate and decrease in standpipe pressure: a wash-out in the drill stem can also cause these indicators. It is important to pick up and check for flow. If there is no flow but the rate of change of pressure is showing an increasing trend, it is probably a wash-out. Either way, it cannot be ignored – action must be taken.

## Increase/Decrease in Drill Stem Weight

Any influx into the wellbore from the formation reduces the density of the annular drilling fluid. This reduces the buoyant force acting upwards on the drill stem. A sensitive weight indicator will register this change as an increase in drill stem weight. For very large kicks, fluid may enter the annulus with enough force to cause a decrease in indicated string weight. At this point, you have probably left things too long and probably have a blowout on your hands.

## Increase in Penetration Rate (Drilling Break)

A marked increase in rate of penetration (ROP) may indicate either changes in the type of formation being drilled or a reduction in the positive difference between the mud pressure and pore pressure.

Generally, the following parameters affect the ROP:

- Rock type
- Formation bulk density/porosity
- Difference between mud pressure and formation pore pressure
- Bit type/wear
- Hydraulics
- Weight on bit
- Rotary speed
- Personnel/equipment.

Drilling breaks (i.e. where the rate of penetration increases significantly) are generally evidence of porosity change. Drilling rate tends to decrease with depth. Thus when a drilling break occurs, it may be an evidence of transition to an abnormal zone. It is crucial at this point to stop drilling and check for flows.

Remember that the work of drilling is a combination of work done by the bit and the mud impact, combined with the effect of pore pressure. If the latter exceeds the downward pressure from the mud, as rock is removed, the pore pressure will tend to break down the formation and assist the work of drilling.

## Lost Circulation

Loss of substantial quantity of mud into the formation will result in reduction in hydrostatic column height. If not checked, this can result in a kick.

## Changes in Gas Levels/Mud Density/Mud Conductivity

Gas extracted from the mud comes from one or more of four sources:

- **Liberated gas** which is the measured gas from the return mud flow, released from the pore spaces of the drilled cuttings. It is the so-called 'background gas' during circulation. If there is overbalance, and the ROP is constant with flow rate, this is liberated gas.
- **Produced Gas** enters the wellbore from adjacent permeable formations when underbalance exists. A background gas increase when ROP is constant is an indicator of produced gas, but…

- **Recycled Gas** is the gas recirculated into the hole, which has not been removed in surface treatment. It appears on detection equipment as an increase in background levels.
- **Contamination Gas** results from chemical breakdown of mud additives. It is usually due to bacterial action.
- **Connection Gas** and **Trip Gas** are short duration gas peaks caused by swabbing action and occur with bottoms up (i.e. the mud which was at the bottom of the hole when the swabbing action occurred reaches surface).

Depending on sensitivity level, surface monitors should detect a relatively steady level of gas extracted from mud during normal drilling. This background gas level may show occasional variations depending on penetration rate, mud pumping rate and the hydrocarbon content of the section drilled. Under normal conditions, the background gas should remain within about 50% of local average. It is crucial that all gas values must be reported whether they are significant or not. Thorough inspection of gas monitoring systems and calibration as part of routine maintenance is essential to preventing potential disasters.

Connection and trip gas are most common while drilling. The connection gas peaks are a clear sign that pressures are near balance, making for optimum ROP. Swabbing is the main cause of connection/trip gas as it creates negative differential pressure. Effects of gas expansion at surface are varied. Evidence includes:

- Rapid fall in flow line mud density
- Increase in return flow
- Mud pit level increase
- Rapid increase in total gas or hydrocarbon levels.

# Well Control Procedures

Control procedures must be initiated immediately after a kick has been detected. Decisions concerning control operation rest on the Company man (the Operator's representative) as well as on the on-site Tool Pusher and drilling engineer. The mud loggers and drilling engineers are responsible for monitoring and recording circulation pressures, gas and pump strokes. The primary and secondary well controls involve the prevention or the removal of influx without damage to the hole, personnel or equipment as well as prevention of further influx.

Kick control procedures involve the following:

1. Shut in the well - follow a predefined procedure
2. Observe shut-in pressures and kick volume
3. Make kill calculations for:
    - Formation pressure
    - BHP to maintain while circulating
    - Kill mud density
    - Initial and final circulation pressures
    - Drill pipe pressure schedules
    - Weighting material volume required
4. Define weighing up and circulating procedure using one of the following methods:
    - Driller's method
    - Wait and Weight method (Engineer's method)
    - Concurrent method (circulate and weight)
    - Top Kill method.

   The first two are preferred for kicks during drilling. The concurrent method requires greater skill and care. The Top Kill method is used when it is impossible to get proper circulation around the system via the drill stem or tubing, or doing so would cause greater problems (exceeding MAASP, casing burst pressure etc).
5. Make interpretation of the influx including:
    - Height and density of influx.
    - Annulus pressure behaviour while circulating.
6. Proceed with circulation using the following guide rules:
    - At all times during circulation, the Bottom Hole Pressure (BHP) must be high enough to prevent further influx;
    - For the safety of the rig and personnel, surface pressure should not at any time exceed the predetermined MAASP value.

   Maintenance of BHP at the proper level is through the application of back pressure via the adjustable choke.

A uniform kick control worksheet should be issued to all well control personnel. Any method based on the above rules is a constant or balanced BHP method of kick control. The variation of the Balanced BHP method is common in different well site. Use differs in the circulation procedure. The methods are based in the step by step procedures listed above but may vary depending on the following situations:

- The bit is at or near bottom
- The top of the influx is below the casing shoe - the weakest point
- The influx is gas.

If the bit is off bottom or top of the influx is above casing shoe, successful influx control may require special procedures. To permit circulation from just off bottom, it would be normal to run in or strip the string back to bottom. Stripping requires the pipe to be run back in with either the annular BOP or pipe rams closed around the pipe, carefully maintaining back-pressure on the well.

## Surface Well Control Equipment

The control equipment is laid out as shown in Figure 1 and is made up of:

1. Blow out preventers - Usually mounted in a stack including annular and ram type preventers. Figure 2 is an example of a BOP stack arrangement of single ram units and annular unit for surface use, showing operation of different components. Figure 3 shows two different makes of annular BOP with varying sealing element design. Principles of operation are essentially the same in both cases; it is the method of deformation of the element that is different.
2. Drilling Spool (Figure 2) for attachment of high pressure choke and kill lines, for circulation with the BOP closed.
3. Casing head (Figure 2) - This is welded to the first surface casing and it provides support and pressure seal for the BOP stack and future casing strings.
4. Choke Manifold and Control Panel (Figure 4 and 5) - To control flow of produced fluids and route them to separator, flare or holding tank or pit. A typical choke manifold includes:
    - One hydraulically operated BOP outlet valve for positive closure
    - Two to four adjustable chokes (variable-opening valves). One or more may be remotely actuated, the others are usually directly operated by handwheel
    - Several manual gate valves.

    The adjustable chokes permit precise control of return flow rate and back pressure.
5. Kelly Cock, Float Valve or Inside BOP (Figure 6) - To prevent back flow via the drill pipe.
6. Mud/Gas separators and Degassers - Equipment for removing gas from mud.

For subsea well control equipment, the layout and configuration are rather different. They may include (Figures 7 and 8):

- Templates - Temporary and permanent guide bases
- Subsea BOP stack
- Marine riser, etc.

Figure 9 shows a double ram type BOP unit generally used in sub-sea BOP stacks, and examples of the internal components used in ram type BOPs.

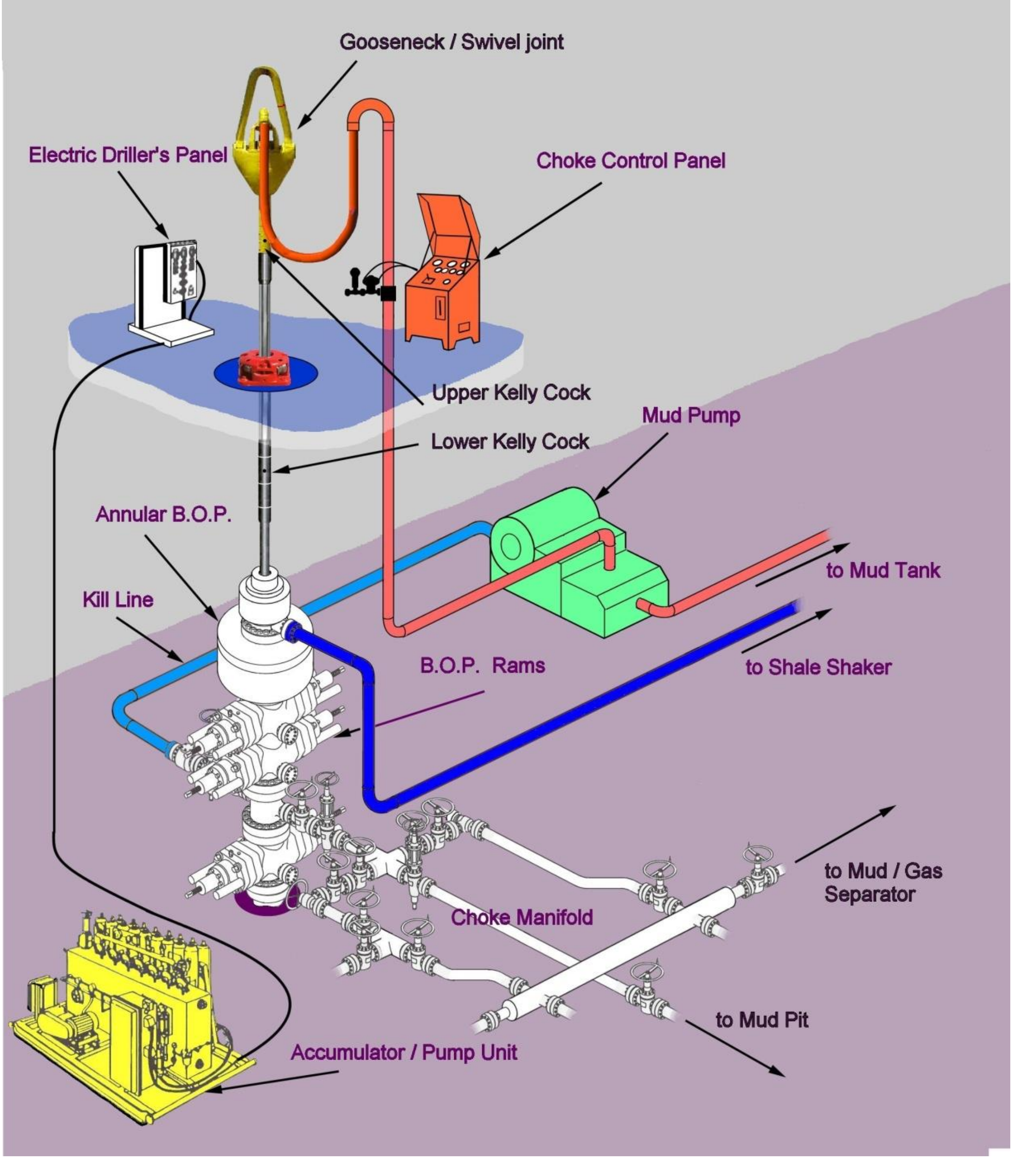


**Figure 1.** Layout of Surface Well Control Equipment.

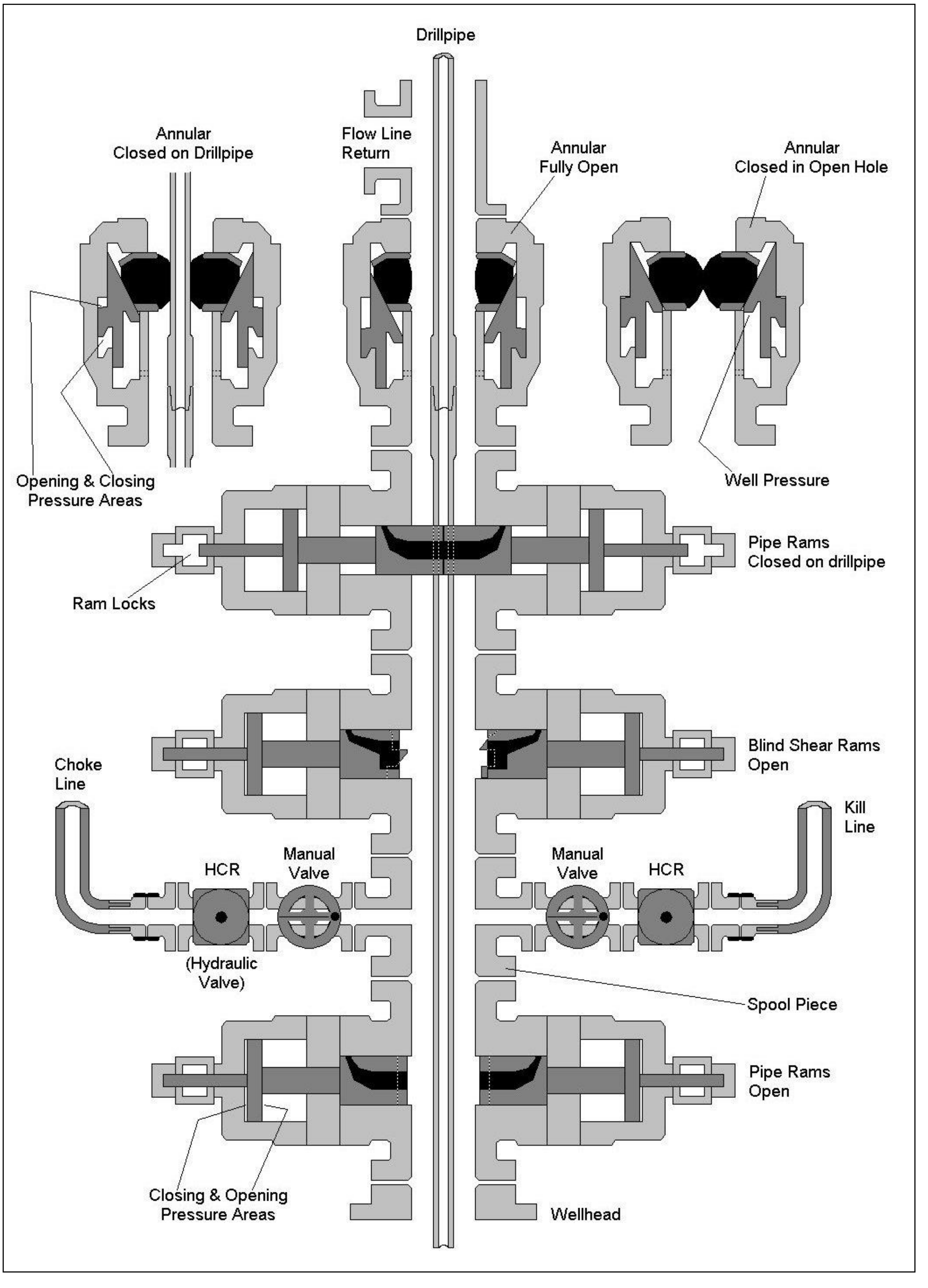


**Figure 2.** Conventional BOP Stack.

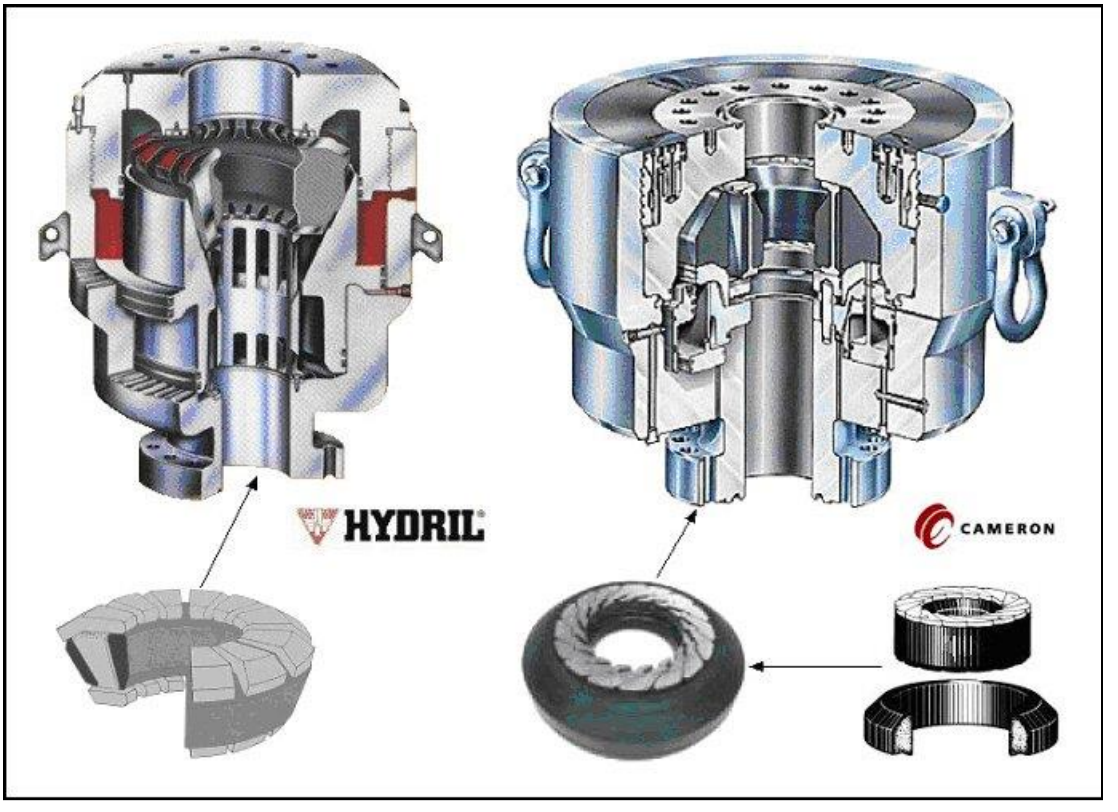


**Figure 3.** Annular BOP Components.


**Figure 4.** Choke Control Console.

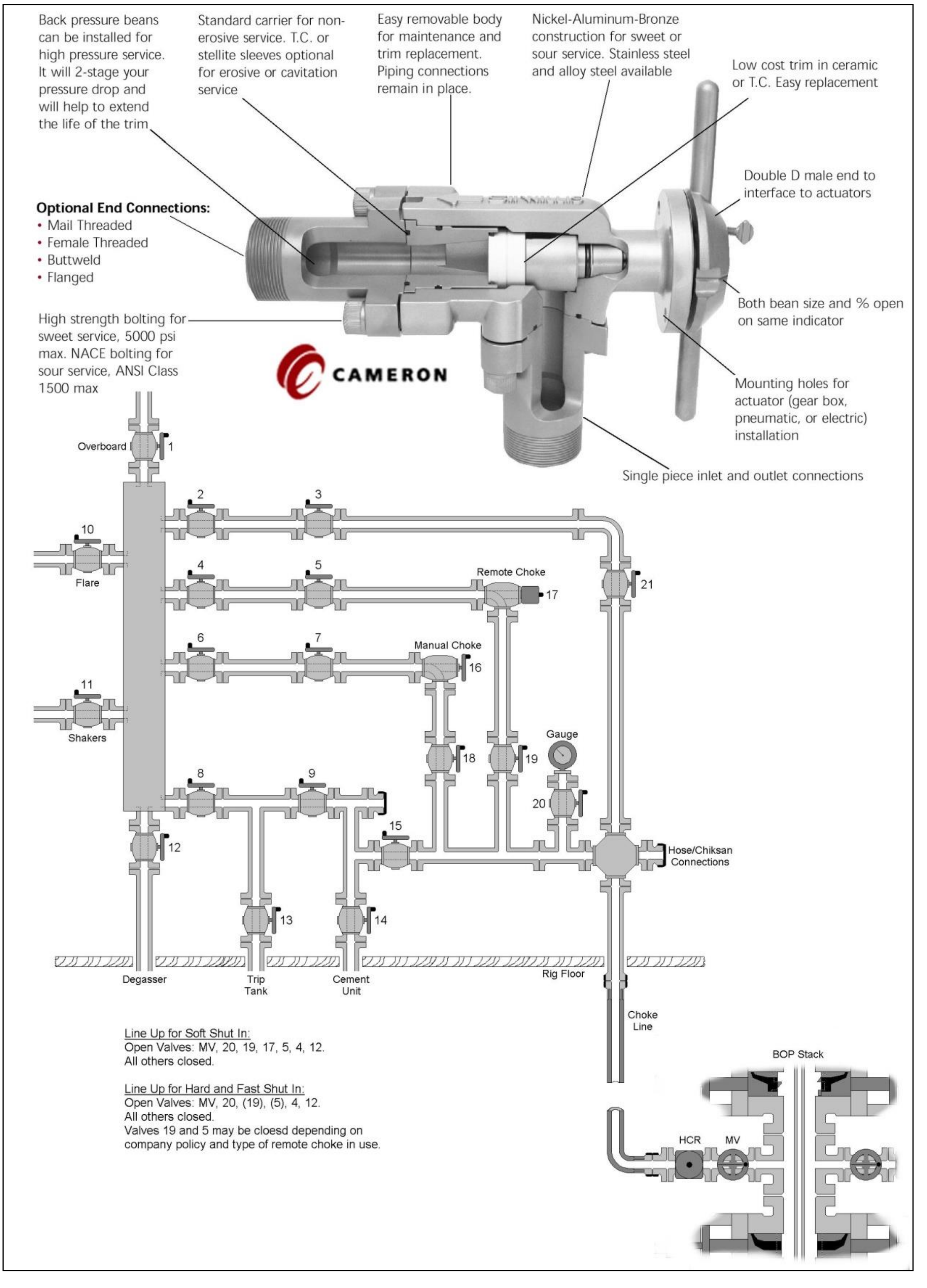


**Figure 5.** Choke Manifold.

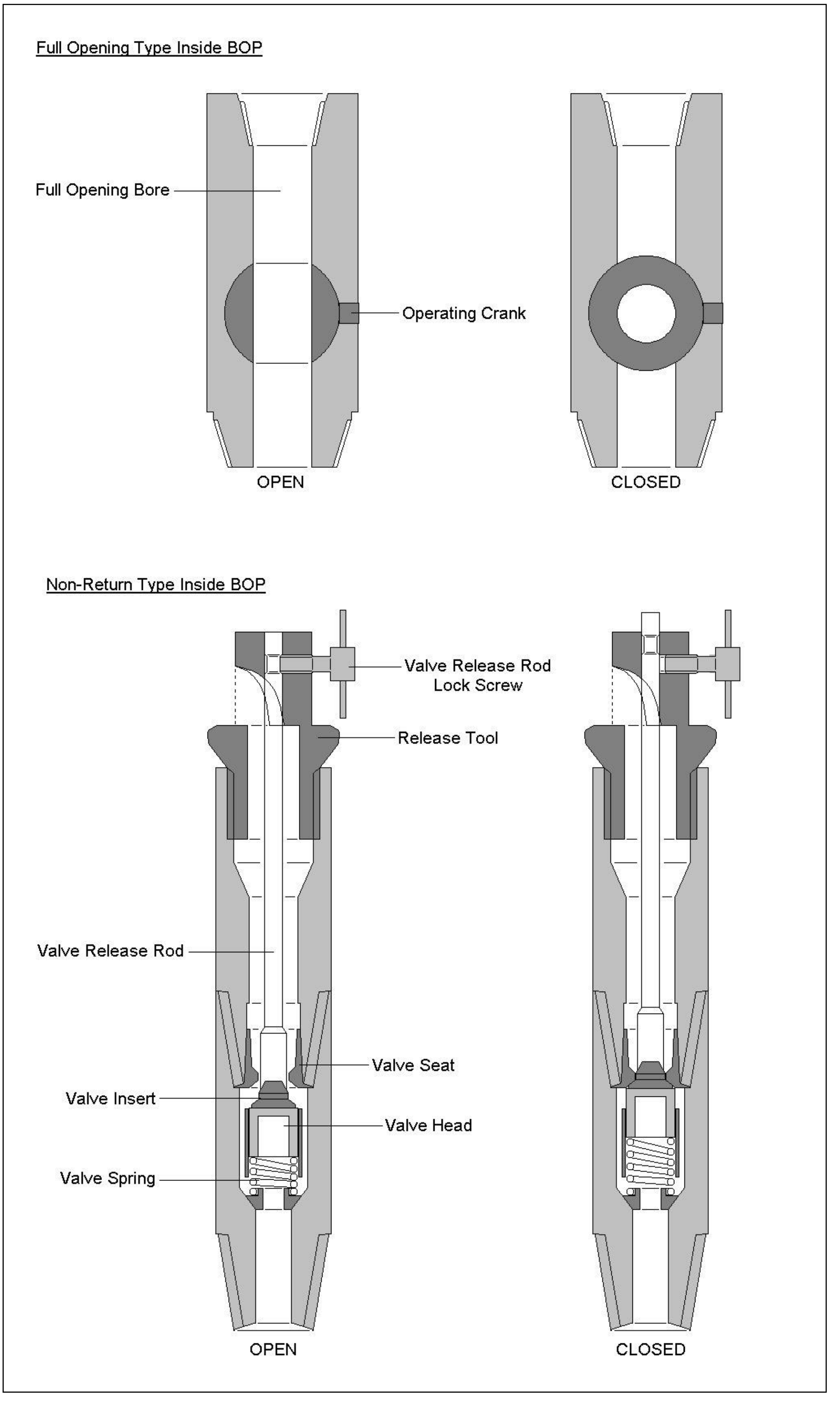


**Figure 6.** Operation of Full Opening and Non-Return IBOP's.

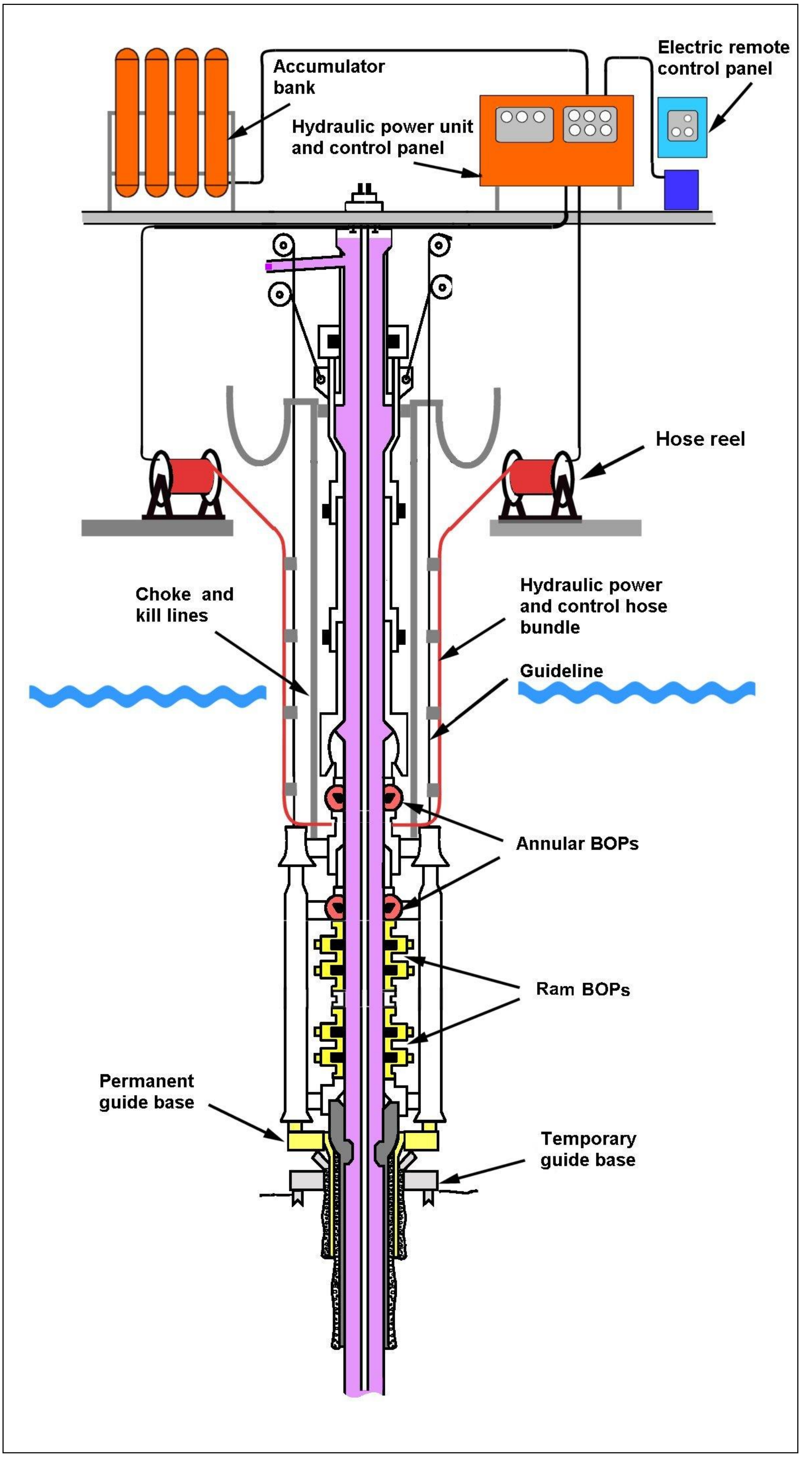


**Figure 7.** Arrangement of Subsea Control Equipment.

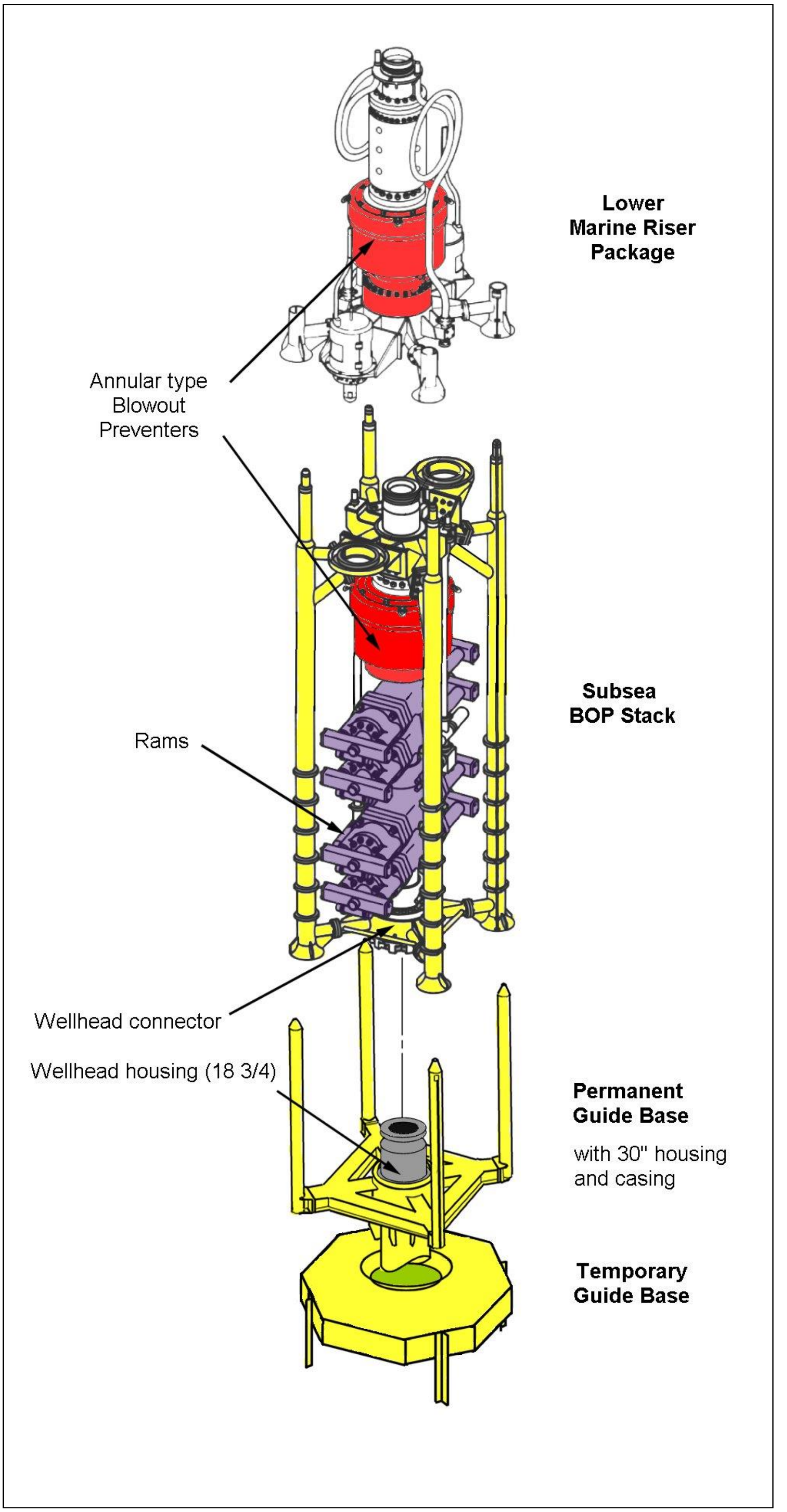


**Figure 8.** Subsea Control Equipment Stackup.

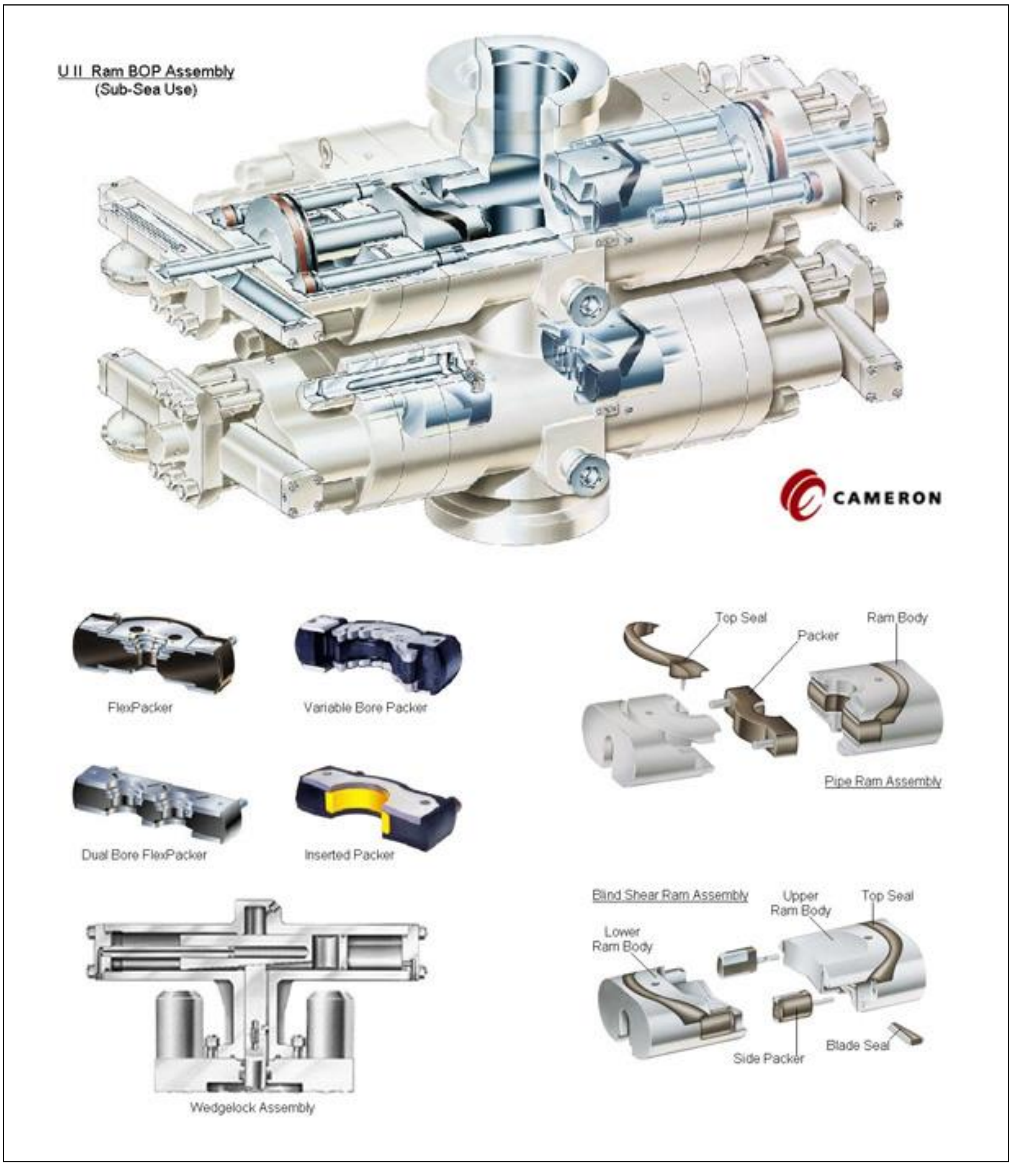


**Figure 9.** Ram BOP Components.

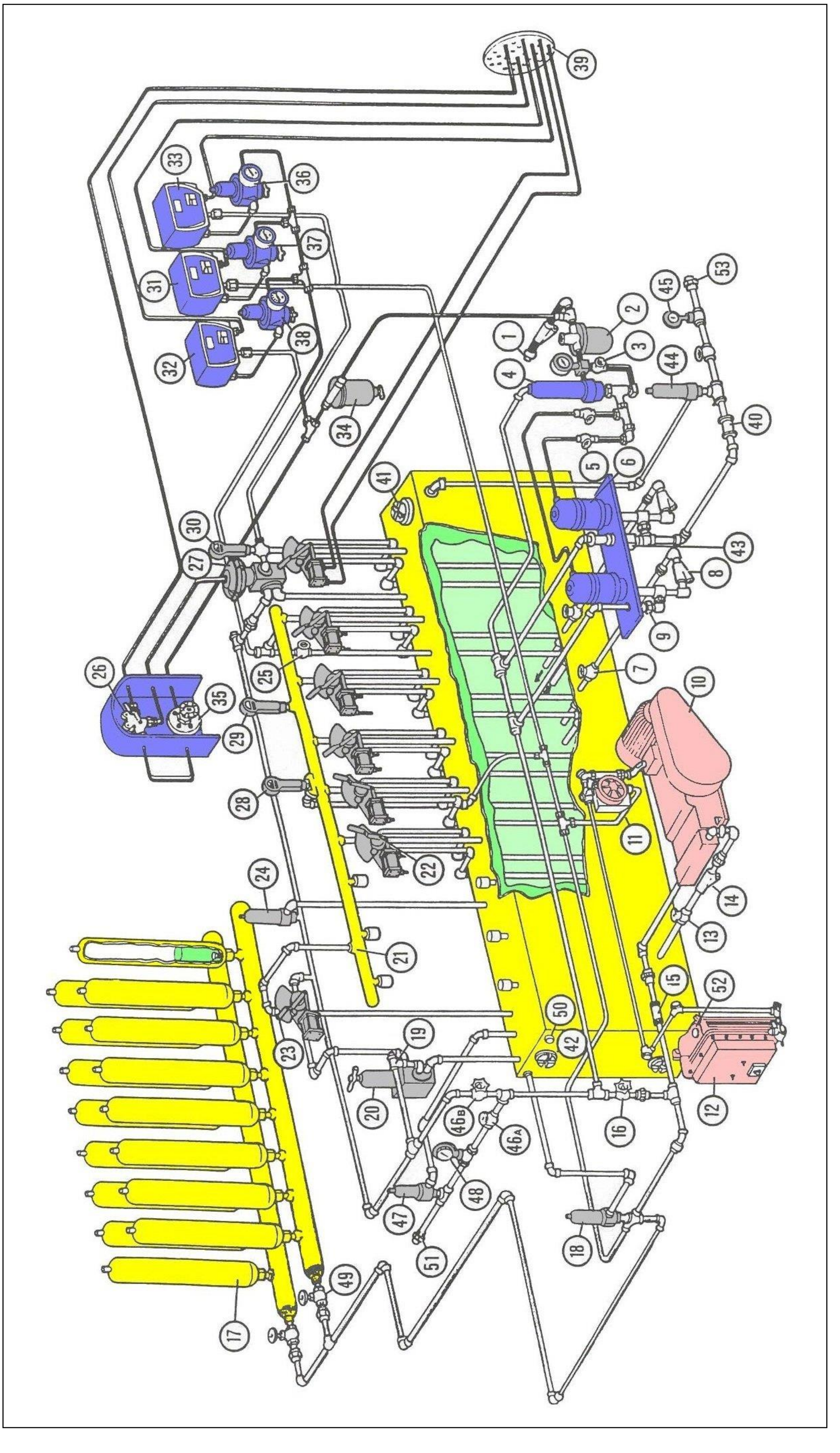


**Figure 10.** Schematic of Conventional Hydraulic BOP Accumulator /Control Unit.

## Key to Figure 10

1. Customer Air supply: Normal Air supply is at 125 psi. Higher air pressure may require an air regulator.
2. Air lubricator: Located on the air inlet line to the air operated pumps.
3. Bypass valve: To automatic hydro-pneumatic switch. When pressures higher than the normal 3,000 psi are required, open this valve. Keep closed at all other times.
4. Automatic hydro-pneumatic pressure switch: Pressure switch is set at 2,900 psi cut-out when air and electric pumps are used. Otherwise at 3,000 psi for air pumps alone. Adjustable spring tension control.
5. Air shut-off valves: Manually operated to open or close the air supply to the air operated hydraulic pumps.
6. Air operated hydraulic pumps: Normal operating air pressure is 125 psi. (For number 88550 pumps, maximum air pressure is 200 psi and for number 88660 pumps maximum air pressure is 125 psi.)
7. Suction shut-off valve: Manually operated. Keep normally open. One for each air operated hydraulic pump suction line.
8. Suction strainer: One for each operated hydraulic pump suction line. Has removable screens.
9. Check valve: One for each air operated hydraulic pump delivery line.
10. Electric motor driven triplex pump assembly.
11. Automatic hydro-electric pressure switch: Pressure switch is set at 3,000 psi cut-out and 250 psi cut-in differential. Adjustable.
12. Electric motor starter (automatic): Automatically starts or stops the electric motor driving the triplex pump. Works in conjunction with the automatic hydro-electric pressure switch and has a manual overriding on-off switch.
13. Suction shut-off valve: Manually operated, normally open. Located in the suction line of the triplex pump.
14. Suction strainer: Located in the suction line of the triplex or duplex pump.
15. Check valve: Located in the delivery line of the triplex line.
16. Accumulator shut-off valve: Manually operated. Normally in open position when the unit is in operation. Close when testing or skidding rig or when applying pressure over 3,000 psi to open side of ram preventers. Open when test is completed.
17. Accumulator: Check nitrogen precharge in accumulator system every 30 days. Nitrogen precharge should be 1000 psi +/- 10%. Action: Use nitrogen when adding to precharge. Other gases and air may cause fire and /or explosion.
18. Accumulator relief valve: Valve set to relieve at 3,500 psi.
19. Fluid strainer: Located on the inlet side of the pressure reducing and regulating valves.
20. Pressure reducing and regulating valves: Manually operated. Adjust to the required continuous operating pressure of ram type BOP's.

21. Main valve header: 5000 PSI working pressure, 1" all welded.
22. 4-way valves: With air cylinder operators for remote operation from the control panels. Keep in standard operating mode (open or close), NEVER in block position.
23. Bypass reducing and regulating valve: With air cylinder operators for remote operation from the control panels. Keep close position, it puts regulated pressure on main valve header (21), and in open position, it puts full pump pressure on the header. Keep in close position unless 3,000 psi (or more) is required on ram type BOP's.
24. Manifold relief valve: Valve set to relieve at 5,500 psi.
25. Hydraulic bleeder valve: Manually operated – normally closed. Note: This valve should be kept OPEN when precharging the accumulator bottles.
26. Panel unit selector: Manual 3-way valve. Used to apply pilot air pressure to the air operated pressure reducing and regulating valve, either from the air regulator on the unit or from the air regulator on the remote control panel.
27. Pressure reducing and regulating valve-air operated: Reduces the accumulator pressure to the required annular BOP operating pressure. Pressure can be varied for stripping operations. Maximum recommended operating pressure of the annular preventer should not be exceeded.
28. Accumulator gauge.
29. Manifold pressure gauge.
30. Annular preventer pressure gauge.
31. Pneumatic pressure transmitter for accumulator pressure
32. Pneumatic pressure transmitter for manifold pressure.
33. Pneumatic pressure transmitter for annular preventer pressure.
34. Air filter: Located on the supply line to the air regulators.
35. Air regulator for pressure and regulating valve. Air operated.
36. Air regulator for pneumatic pressure transmitter (33) for annular pressure.
37. Air regulator for pneumatic pressure transmitter (31) for accumulator pressure.
38. Air regulator for pneumatic pressure transmitter (32) for manifold pressure. Note: Air regulator controls for pneumatic transmitter normally set at 15 psi. Increase or decrease air pressure to calibrate panel gauge to hydraulic pressure gauge on unit.
39. Air junction box: To connect the air lines on the unit to the air lines coming from the remote control panel through air table.
40. Rig test check valve.
41. Hydraulic fluid fill port.
42. Inspection plug port.
43. Rig test outlet isolator valve: High pressure, manually operated. Close when rig testing-open when test is complete.
44. Rig test relief valve: Valve set to relieve at 6500 psi.
45. Rig test pressure gauge.

46. (a) Rig skid outlet.
    (b) Valve header isolator valves: Manually operated. Close valve header isolator valve and open rig skid isolator valve when rig skidding. Open valve header isolator valve and close rig skid isolator during normal drilling operations.
47. Rig skid relief valve: Valve set to relieve at 2,500 psi.
48. Rig skid pressure gauge.
49. Accumulator bank isolator valves: manually operated. Normally open.
50. Rig skid return. Customer's connection.
51. Rig skid outlet. Customer's connection.
52. Electric power. Customer's connection.
53. Rig test outlet. Customer's connection.