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Deepwater Mux Subsea BOP Control System & Marine Riser System

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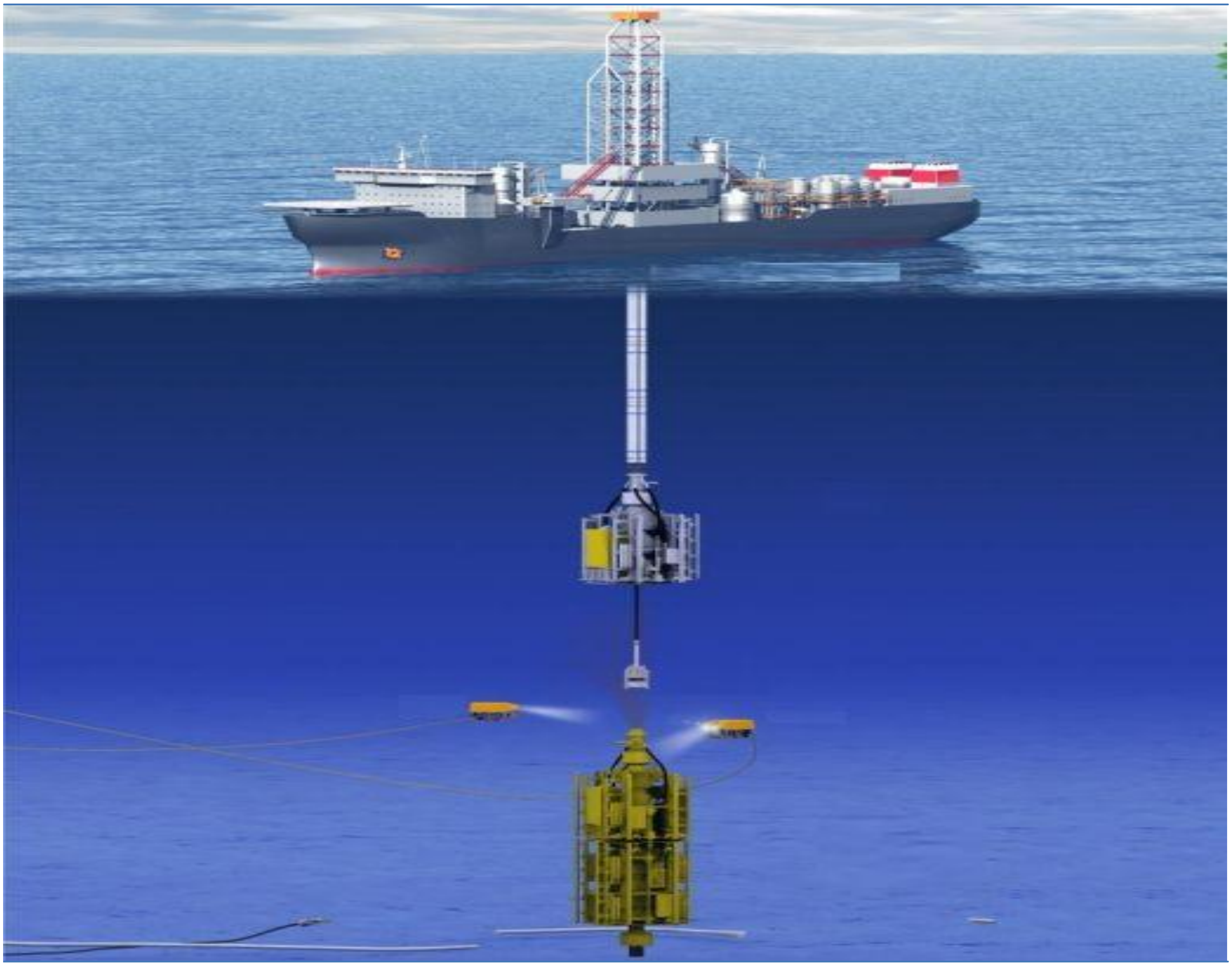

Deepwater Subsea BOP Control Systems & Marine Riser Systems

Written by

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Section A – Subsea BOP Control System

Section B – Marine Riser System

Section C – Testing of BOP System

Section D – Recommended Pressure Test Practices, Floating Rigs with Subsea BOP stacks.

Section E – Job Safety Analysis for BOP Maintenance and Inspection.

Section A – Subsea BOP Control System

1.0 Introduction

Each component in a Blow Out Preventer (BOP) assembly is operated hydraulically by either moving a piston up and down or back and forth. One of the most important functions of a BOP Control System is to direct hydraulic fluid to the appropriate side of the operating system and to provide a means in which fluid on the other side of the piston can be expelled.

On land, jack up or platform drilling operations the control of the BOP is easily achieved in a conventional manner by connecting each BOP function directly to a source of hydraulic power situated at a safe location away from the wellhead.

Operation of a particular BOP function is then accomplished by direct control i.e. directing hydraulic power from the control unit back and forth along two large bore lines to the appropriate operating piston. Again, on land, jack up or platform drilling operations – **BOP system uses the minimum number of controlling valves to direct the hydraulic fluid to the required function. It also enables the returning fluid to be returned to the control unit for further use.**

For subsea drilling operation, direct control cannot be applied due to the fact that the resulting control line connecting the BOP to the surface will be prohibitively large to handle.

Reaction time would also be unacceptable due to the longer distances to the BOP functions and the consequent pressure drop.

In order to overcome these problems indirect operating systems have been developed.

There are three types:

1. Hydraulic System

2. Multiplex Electro-Hydraulic System.
3. Acoustic Systems

1.1 Indirect Hydraulic System

For indirect hydraulic system, the size of the control umbilical is reduced for deepwater application as the hydraulic control function (hydraulic lines) is split into two (see Fig 1.0):

I. Hydraulic line that transmits hydraulic power (power fluid) to the BOP down a large diameter line located at the center of the control umbilical.

II. Hydraulic lines that transmit hydraulic signals (pilot fluid) down smaller lines to pilot valves.

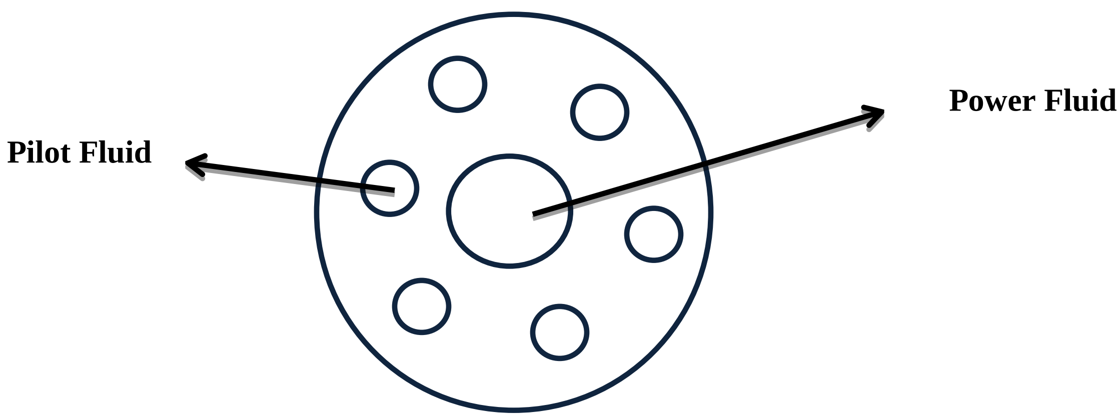


Fig 1.0: Control Umbilical used to transmit power fluid and pilot fluid

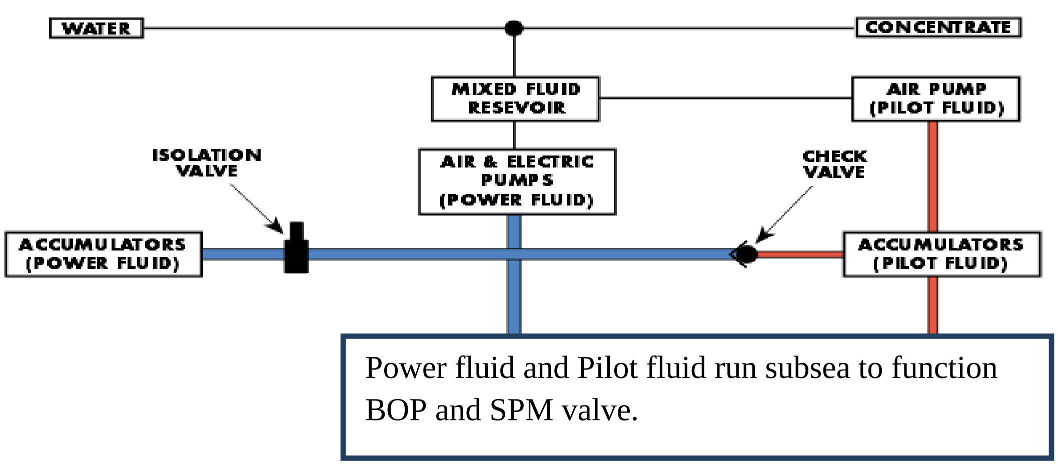


Fig 1.1: Schematic of Control Umbilical section used to transmit power fluid and pilot fluid

Once the hydraulic power fluid is used to open or close a function on the BOP, no attempt is made to recover the hydraulic fluid and thus vented subsea through the subsea control pod. **Venting it at the surface will increase the number of lines in the umbilical.** This will be discussed in details in latter section.

1.2 Multiplex Electro Hydraulic (MUX) System

In deeper and ultra deep waters the problems of umbilical handling and reaction time to transmit pilot fluid and power fluid to there respective functions became more significant due to the long step out.

In order to overcome this change, hydraulic lines transmitting the pilot fluid to the pilot valves were replaced with electrical cables which operate solenoid valves. Hydraulic signal is then sent from this valve to the relevant pilot valve which in turn is actuated and direct power fluid to its associated BOP function (see Fig. 1.2). This diagram will be discussed in details.

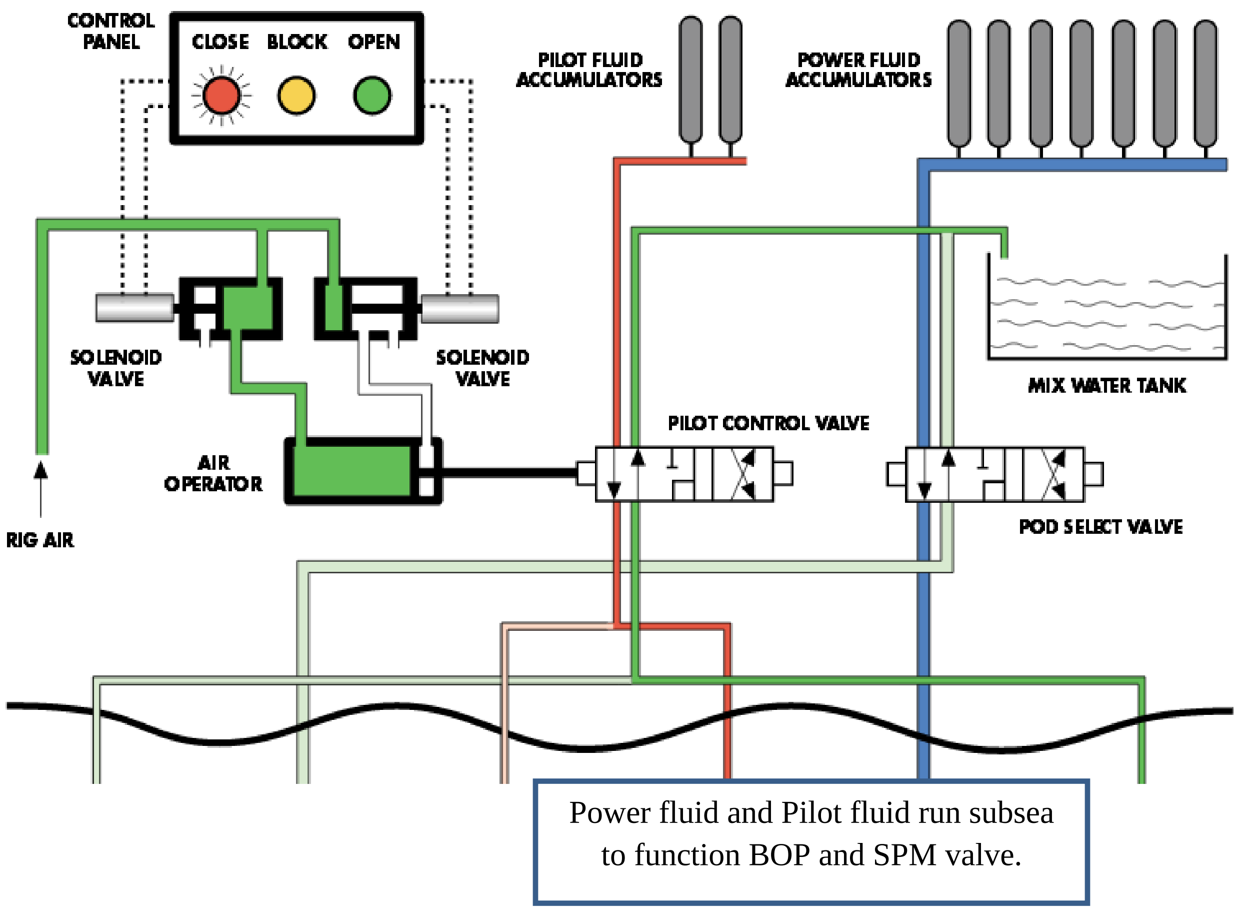


Fig 1.2: Schematic of MUX section used to transmit power fluid and pilot fluid

The time division multiplexing system provides simultaneous execution of commands and results in a relatively compact electrical umbilical is fast compared to hydraulic system.

The MUX control umbilical consist of four power conductors, five conductors for signal transmission and additional backup and instrumentation lines.

With the armored sheath the umbilical has a resulting diameter of some 1.5 inches with a weight of about 3 Ibs/ft in air.

1.3 Acoustic System

In addition to either of the primary control methods mentioned above the Subsea Bop Stack can also be equipped with an acoustic emergency back up system.

In principle this is similar with the other two systems i.e. hydraulics & electro hydraulics. The main difference is the replacement of the hydraulic or electric commands to the pilot valves with acoustic signals. Being a purely backup system the number of commands is limited to those which might be required in an absolute emergency.

1.4 Manufactures of BOP Control System

The main manufacturers of control systems are:

1. Cameron Iron works
2. NL Shaffer
3. Koomey
4. Valvcon Division of Hydril

In order to interpret the general concept since these are probably the most common, emphasis will be placed on the **NL Shaffer and Koomey Systems.**

2.0 Overview of Subsea BOP Control System Configuration

Fig. 2.0 below shows the general arrangement of subsea BOP control system.

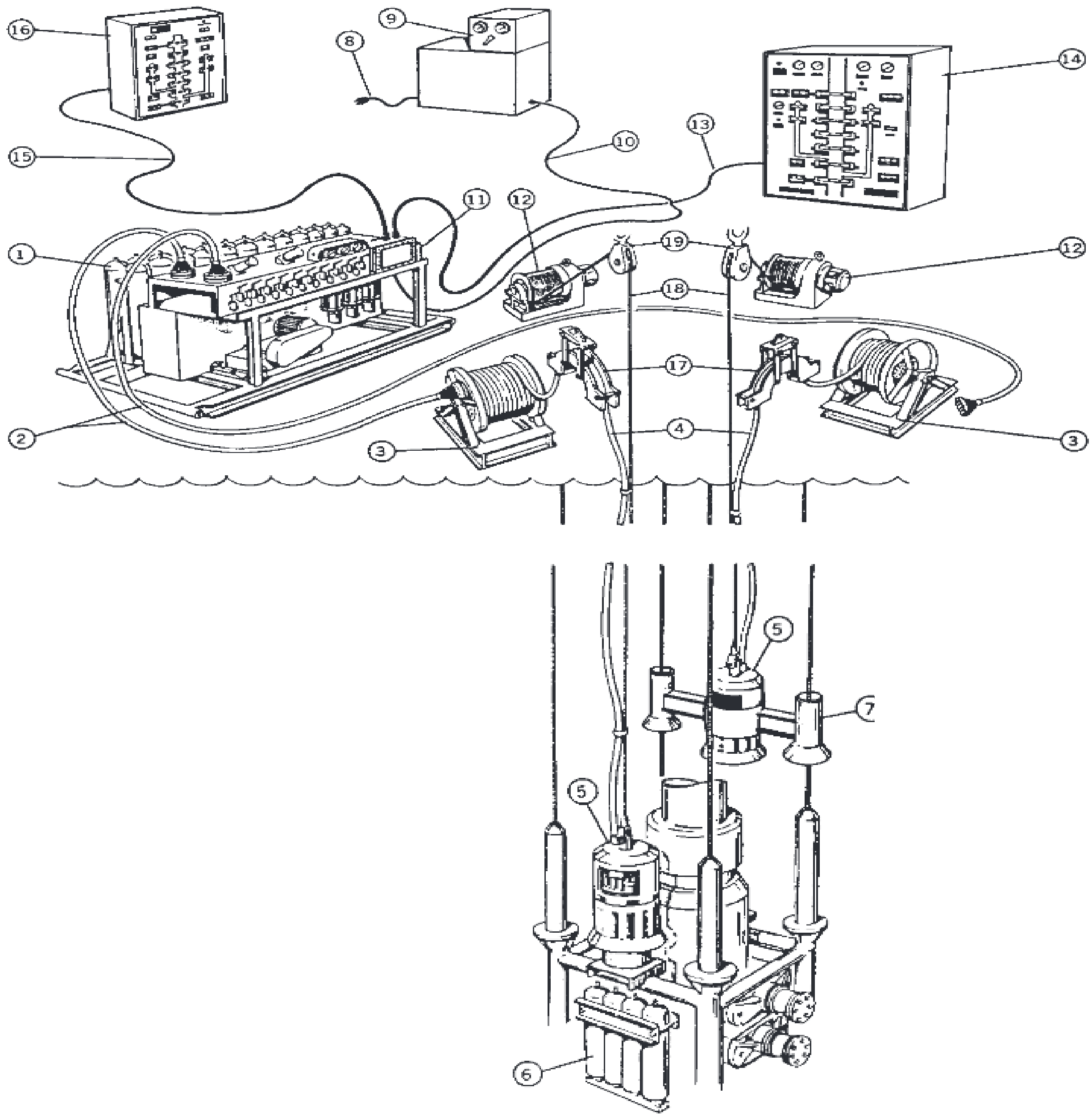


Fig 2.0: General overview of Subsea BOP control system (ref. Well Control for the Rig-Site Drilling Team, Aberdeen Drilling School).

2.1 Subsea BOP Control System – Equipment List

1) Hydraulic Power Unit with Pumps
2) Hydraulic Jumper Hose Bundles
3) Subsea Hose Reels (with Manual Control Manifold)
4) Subsea Hydraulic Hose Bundle
5) Subsea Control Pods
6) Subsea Accumulators
7) Retrieving Frame for Subsea Pods
8) Electric Control Power Supply Cable
9) Electric Power Pack
10) Electric Power Cable to Control System
11) Central Hydraulic Control Manifold
12) Air Winches for Running Subsea Pods
13) Master Electric Panel Control Cable
14) Master Electric Panel
15) Electric Mini Panel Control Cable
16) Electric Mini Panel
17) Sheaves for Subsea Hose Bundles
18) Wire Lines to Subsea Pods
19) Sheaves for Wireline to Control Pod

Fluid used to operate the BOP Stack (Power Fluid & Pilot Fluid) is delivered from the hydraulic power unit (HPU) on command from the central hydraulic control manifold (CHCM). CHCM contains the valves which direct pilot pressure to the pilot valves in the subsea control pods and power fluid to function BOP subsea (see Fig. 2.1). **CHCM is operated either manually or by solenoid actuated air operator.**

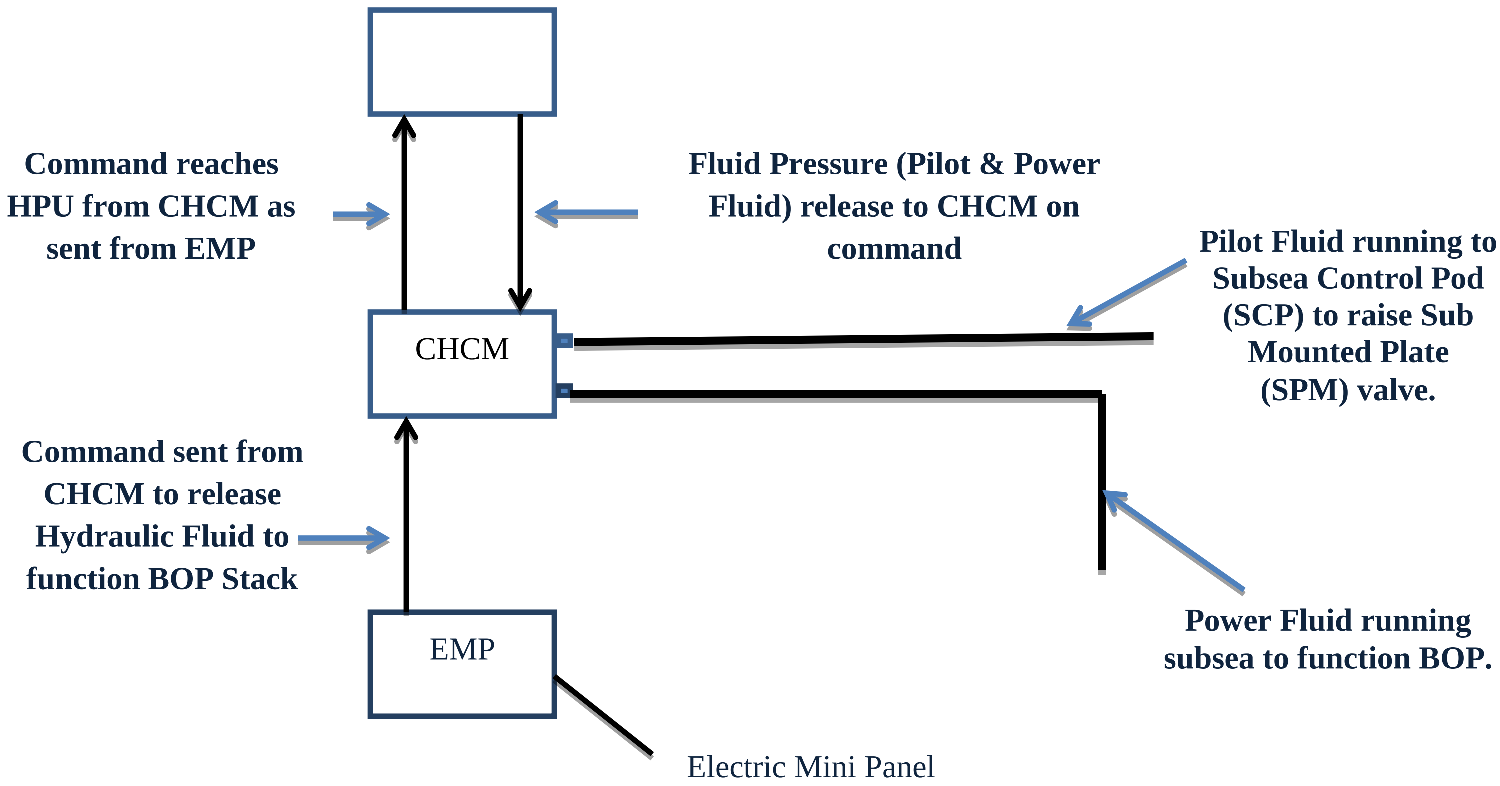


Figure 2.1 – Diagrammatical representation of commands from EMP to CHCM and then to HPU in order to release pilot & power fluid to function BOP stacks.

The master electric panel (MEP) located on the rig floor is used to control the CHCM remotely via solenoid activated air operator.

Note: The pilot fluid is sent to the Subsea Control Pods (SCPs) through individual, small diameter hoses bundled around the large diameter hose which delivers the power fluid (see fig. 1.0).

2.2 General Operating BOP Control System Sequence

A detailed description of the sequence of events that occur when a function is operated will now be presented with the flow diagram in fig. 2.2

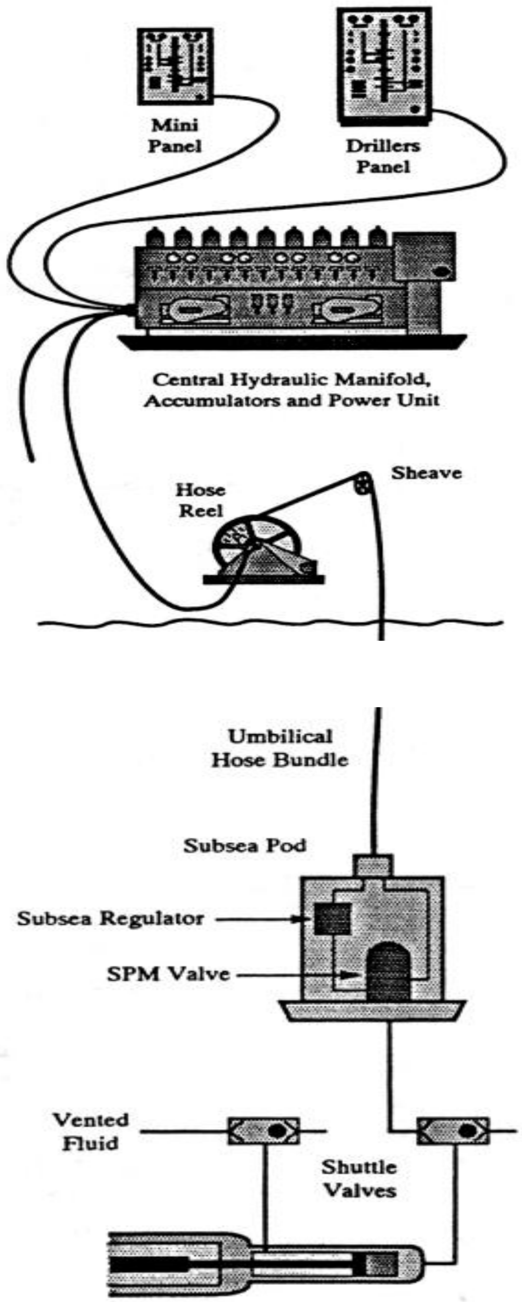


Figure 2.2:- BOP Ram or Annular Operating Piston

2.2.1 General Operating BOP Control System Sequence – Pilot Fluid Circuit

When a function button on either the **mini panel** or **Drillers panel** is pushed an **electrical signal** is sent to the associated **solenoid valve** on the **Central Hydraulic Manifold** (see fig 2.2).

The **solenoid valve** moves to allow **high pressure air** to pass through it and actuate its corresponding **pilot control valve** (see fig 2.2).

When the **pilot control valve** is activated, **hydraulic fluid** is allowed to flow from the **pilot accumulators (where it is stored at 3,000 psi)** and down the appropriate **pilot lines in each of the umbilical hose bundle** (see fig 2.2).

The **pilot line terminates** in the **subsea pod at the SPM valve**. When **activated by the pilot pressure**, this **valve lifts to allow power fluid (at its regulated pressure)** to flow to its associated BOP function (see fig 2.2).

Most BOP stack function are fail safe valve, which requires pressure to close or open called a **two position function** or pressure to block, close and open called **3 position functions.** The difference is in their number of **solenoid valves**. For two position function, the control valve ¼ inch manipulator valve can be controlled from remote panel via **2 solenoid valves** which can place the valve either in the operate ‘’open’’ or ‘’vent’’ positions. A pressure switch connected to the discharge line is activated when a pilot signal is present and lights up the appropriate lamp on the control panel. This is mainly used for **surface BOP control system**. For **indirect hydraulic or MUX subsea systems** requiring pressure to both open and close is called **3 position functions.** The hydraulic pilot fluid circuit for a **3 position function** requires the use of **3 solenoid valves** (see fig. 2.3). The **block solenoid valve** is being used in conjunction with **two shuttle valves** in order to **centre the control valve.**

A **pressure switch** is connected to **each discharge line of the control valve** and will transmit a **signal** to the appropriate **control panel lamp** whenever **a pilot signal is present**. The operation of the 3 position function is discussed below.

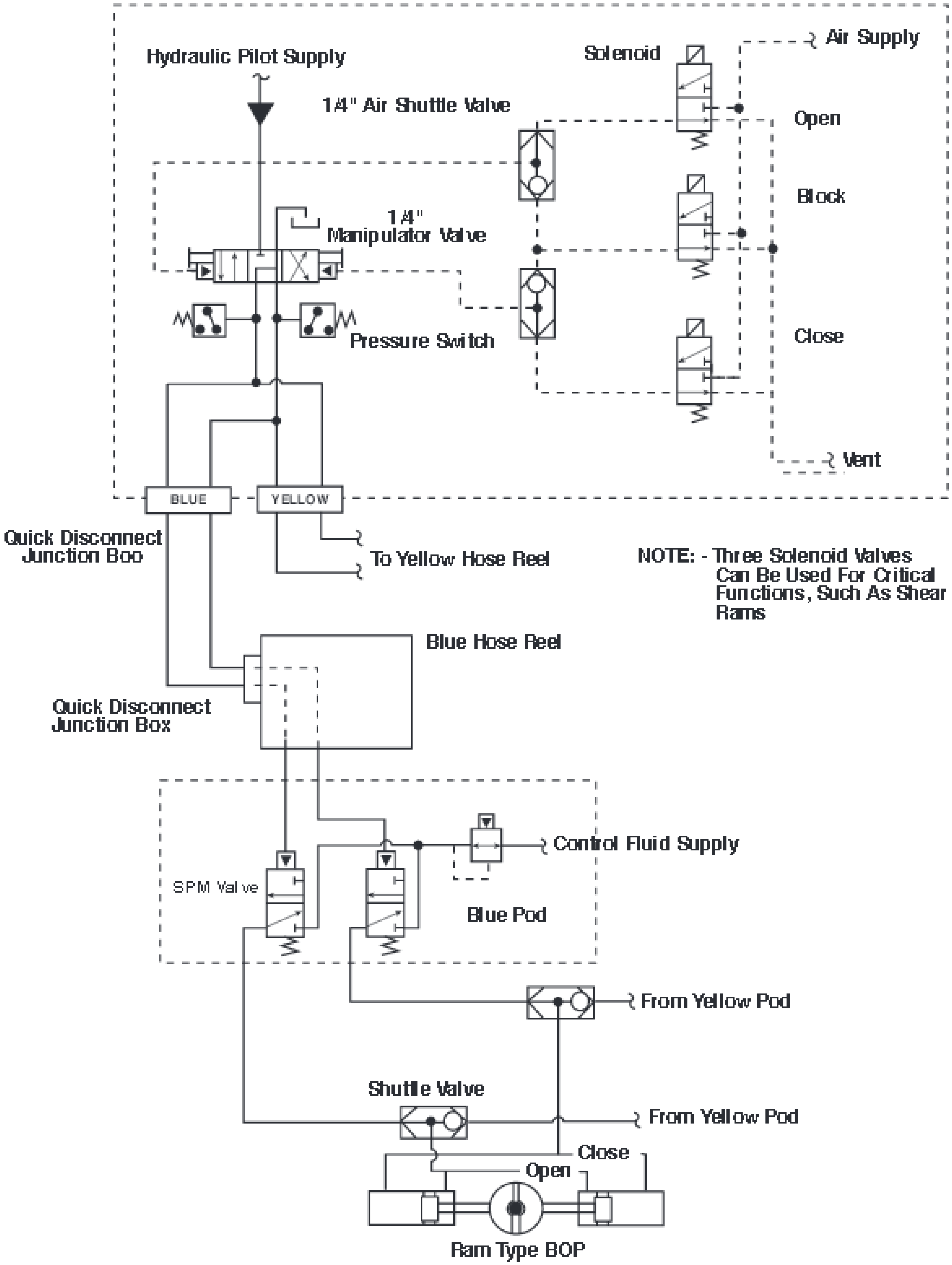


Figure 2.3:- Pilot Fluid Circuit (3 – Position Function)

2.2.2 General Operating BOP Control System Sequence – Control Fluid Circuit

The position of the **pod selector valve** on the **Central Hydraulic Control Manifold** determines to which of the **two subsea control pods** the **hydraulic power fluid** is directed.

The fluid is stored in the **accumulators at 3,000 psi** and is sent to the **subsea pod** through a **1" hose** in the center of the **umbilical bundle**.

When the **power fluid reaches the pod** it goes through a **regulator which reduces its pressure to 1,500 psi.** (This value can be adjusted from **surface via a pilot control circuit**).

Power fluid, at its regulated pressure, passes through the **activated SPM valve** to the **BOP function via a shuttle valve.**

Hydraulic fluid on the **opposite side of the BOP function** returns through its **shuttle valve** to an **SPM valve in one of the subsea pods** from where it is **vented at ambient condition.**

In general, the **subsea BOP Control System control valve is a four –way, three position valve** and can be **functioned manually or by an air operator**. The 3 position of the control valve i.e. close, open & block function will be discussed as follows (see fig 2.4).

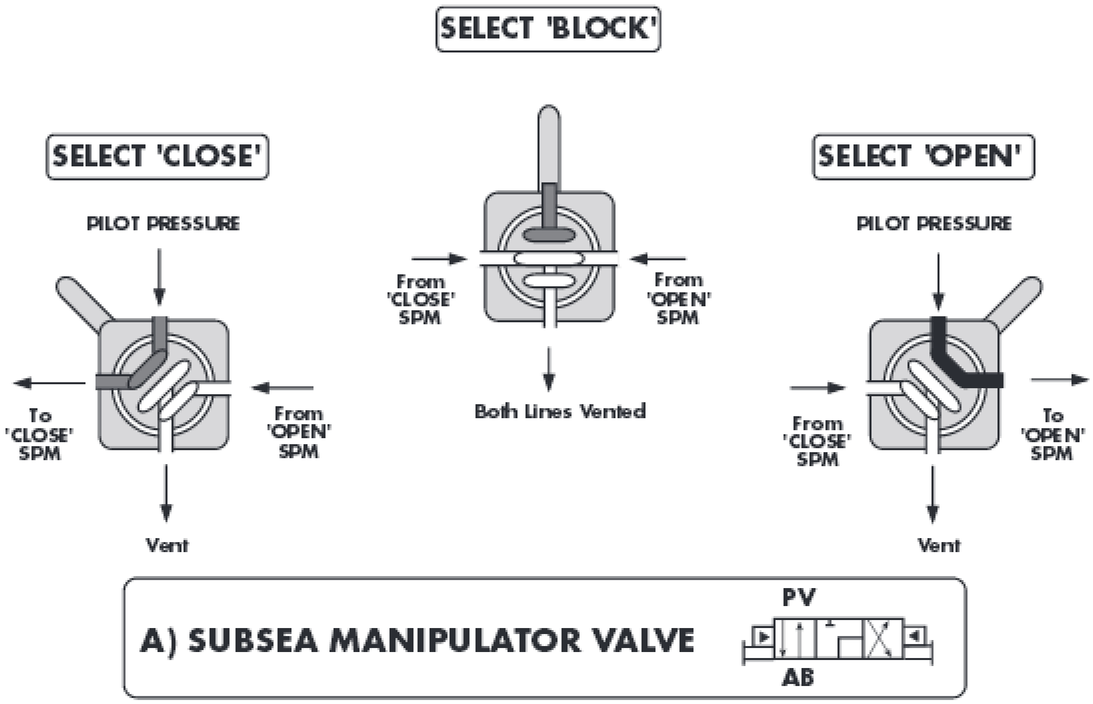


Figure 2.4:- 3 Position Subsea Manipulator Valve

2.2. 3 Subsea Manipulator Valve – Close Function

In figure 2.5:- one of the BOP rams is being closed using the drillers master control panel. Pushing the **''close''** button on this panel **actuates the solenoid valves** on the **central hydraulic control manifold** thus allowing **air pressure** to move the **pilot control valve** to the **''close'' position**. The **solenoid valve on the right in the diagram vents** the other side of the **air cylinder.**

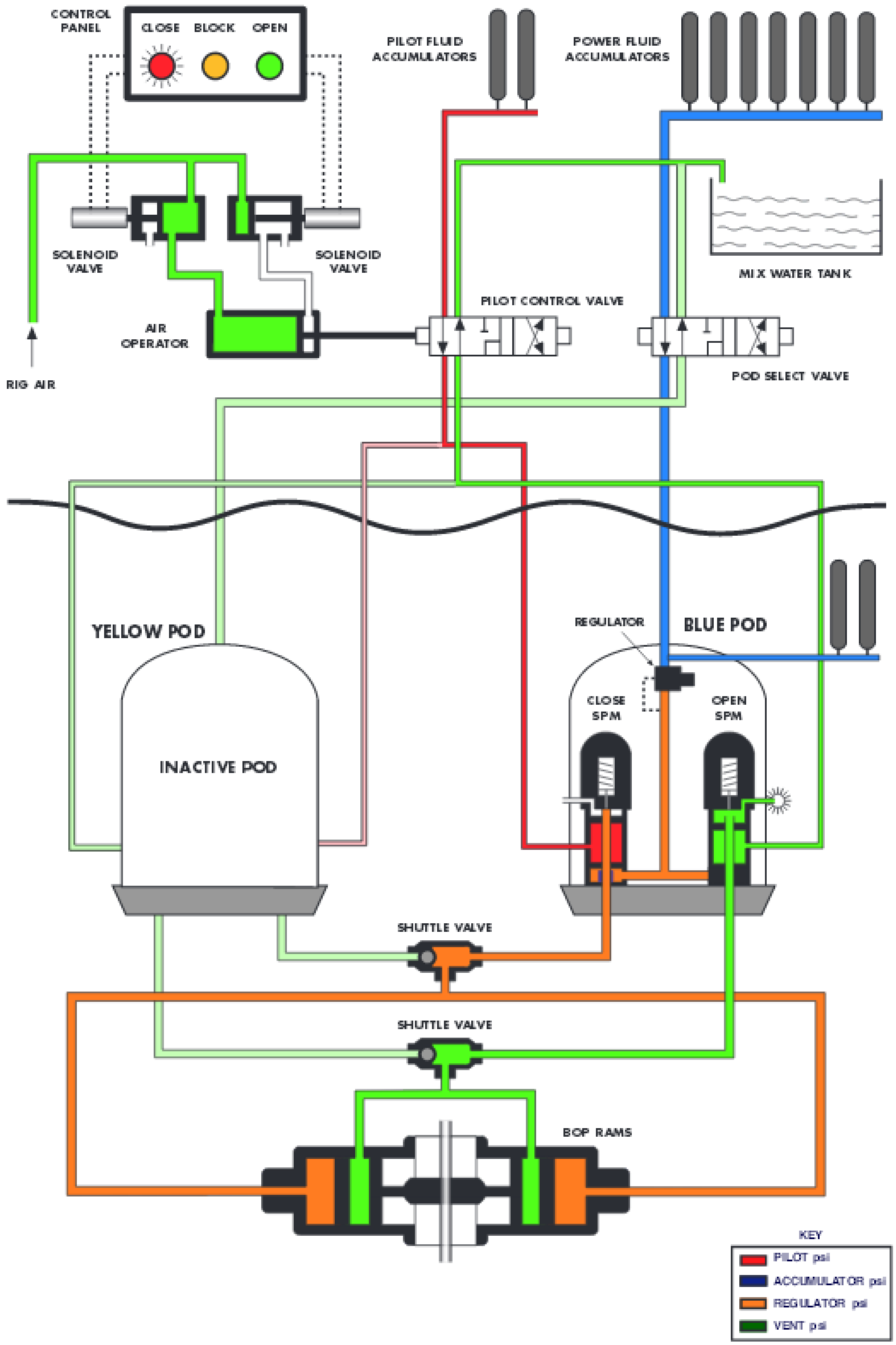


Figure 2.5:- Subsea Manipulator Valve – Close Function

With the **pilot control valve** in the **''close'' position**, **pilot fluid** at **3000 psi** is sent down the umbilical to the **RAMS CLOSE SPM valve** in the **subsea control pods.** The **pressure lifts** the **spindle** in this valve so that it **seals against**: **the upper seat, thus blocking the vent.**

At the same time **power fluid** at its **regulated pressure** is allowed **past the bottom of the spindle** and into the **valve block in the male and female sections** of the **subsea control pod**. From the bottom of the **female section**, the **power fluid** then **travels through the shuttle valve** to the **''close'' side** of the **BOP ram cylinder.**

Simultaneously **reciprocating action in the RAMS OPEN SPM valve, vents the hydraulic fluid** from the **'open' side** of the **BOP ram.**

2.2. 4 Subsea Manipulator Valve – Open Function

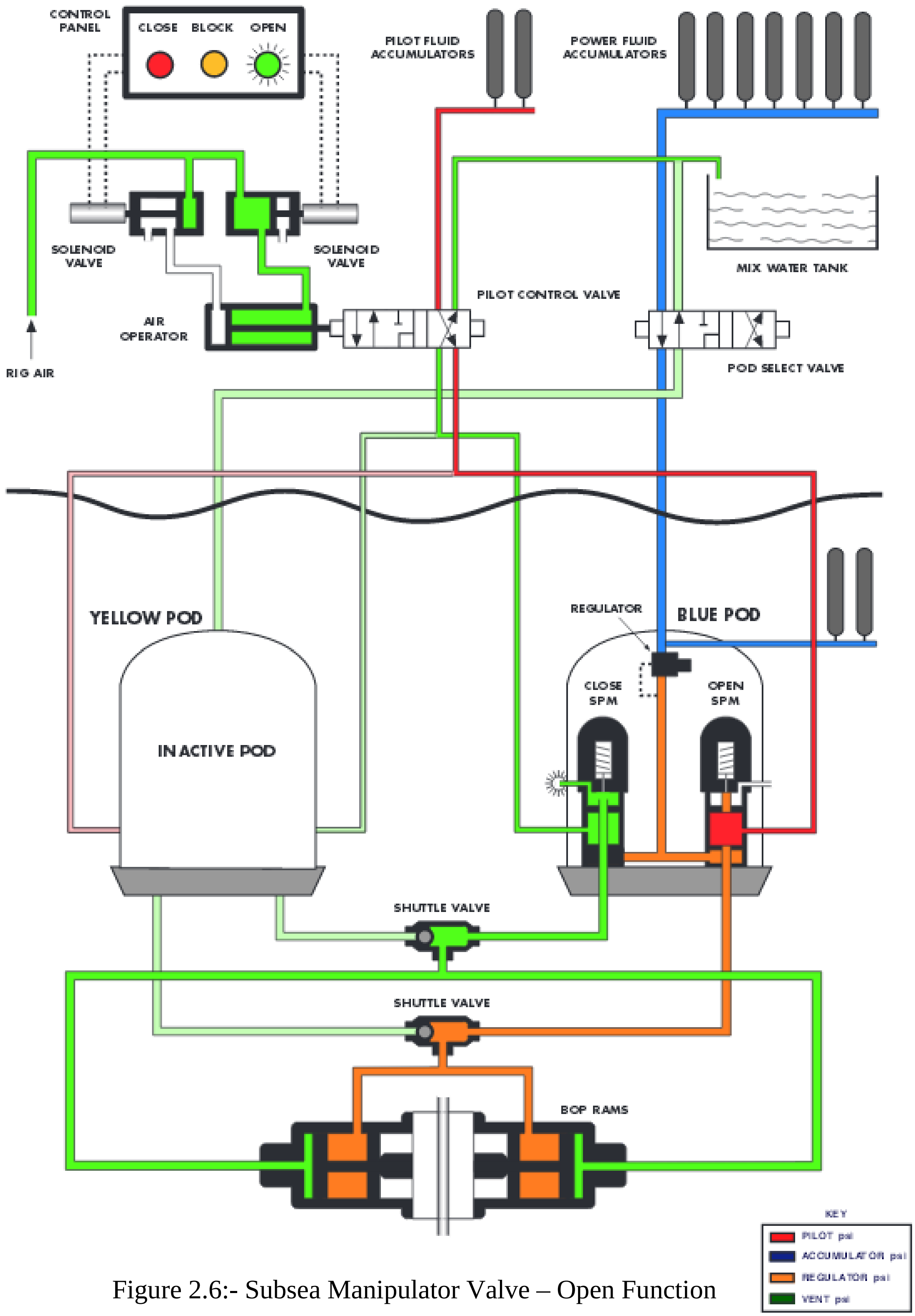


Figure 2.6:- Subsea Manipulator Valve – Open Function

This sequence is the parallel opposite of the close function. As shown in fig. 2.5 above, when the **‘’open’’ button is pressed**, the **solenoid valves** on the **central hydraulic control manifold** are **actuated** and **allow air pressure** to move the operator on the **pilot control valve** to the **‘’open’’ position**. The **solenoid valve** on the left in the diagram **vents the ‘’close’’ side** of the operating **piston.**

The **pilot fluid** can then flow down the **subsea control pod** where it **lift the spindle in RAMS OPEN SPM valve** thus **blocking the vent** and **allowing power fluid** to flow through the valve. From the **subsea control pod** the **power fluid travels** through the **‘’open’’ side** of the **BOP ram operating cylinders**. Simultaneously reciprocal action in the **RAM CLOSE SPM valve** allows the fluid from the **‘’close’’ side** of the **operating cylinder to be vented** through the **RAM CLOSE SPM valve.**

2.2.5 Subsea Manipulator Valve – Block Function

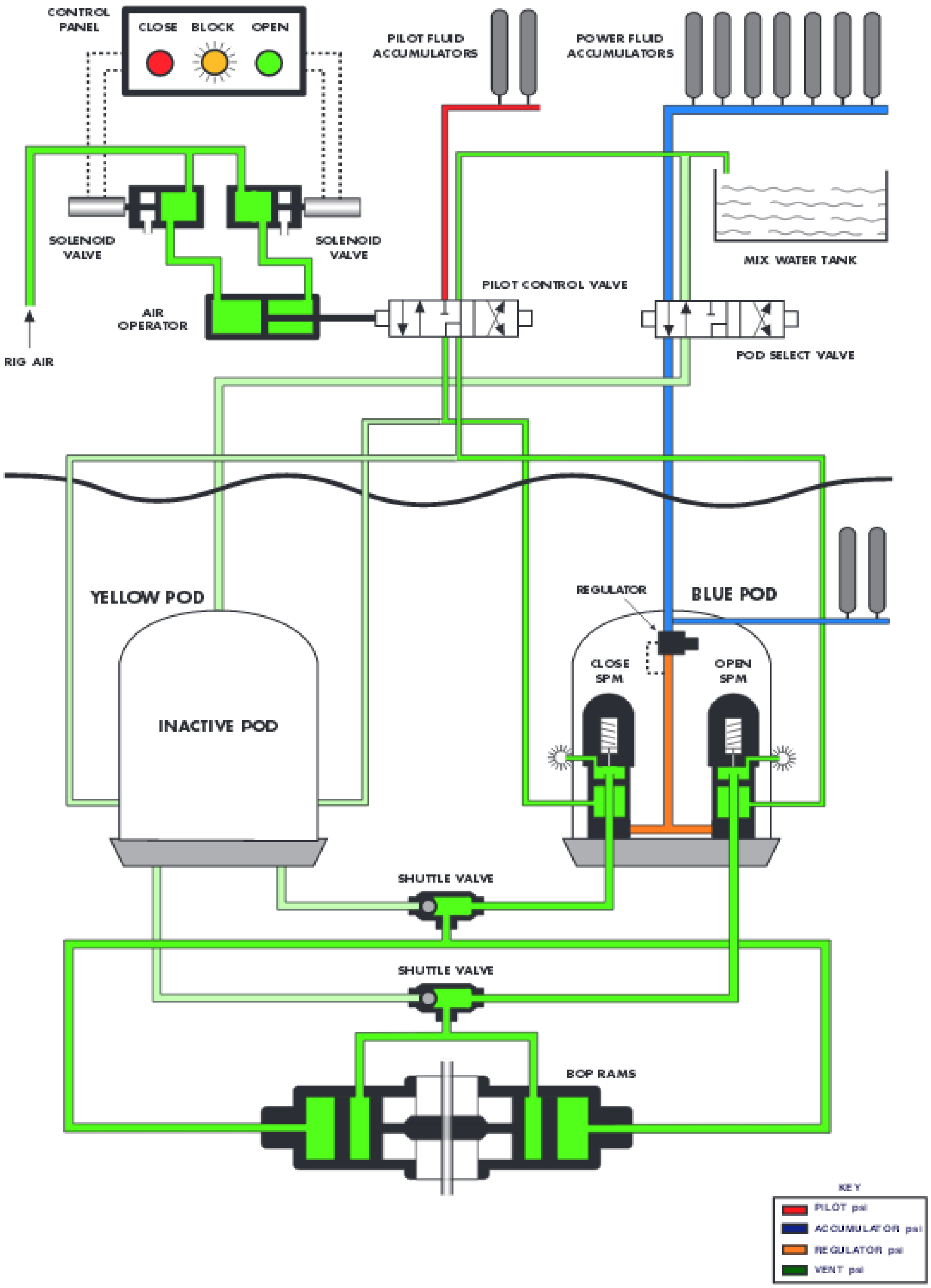


Figure 2.7:- Subsea Manipulator Valve – Block Function

The **block function** is used to **vent a pilot control valve**. By doing this individually on each **valve** a **leak in the control system** or **the preventers** can be **located and isolated**. By **centering and venting** all the **valves** when the **accumulator unit** is first being **pressurized, unintentional** and **inadvertent operation** of the various other **positions and functions** can be eliminated.

Referring to fig. 2.7, above: - when the **‘’block’ ’button is pressed**, both the **solenoid valves** are **actuated** in such a way as to apply **pressure to both sides of the air operator**. This causes the **pilot control valve** to be **centred** which then allows **both the pilot ‘’open’’ and ‘’close’’ lines to be vented.** The **springs in both the SPM valves in the subsea control pod** then **push the spindle down** so that the **seal against the bottom seats** and **block the flow** of **any power fluid through the valves.** At the same time this also **vents both sides of the BOP ram operating cylinder.**

In addition to the control fluid circuit used to **operate stack functions** such as **ram or annular preventers,** the control system must also perform the other functions such as **control of subsea regulators, provide read back pressures, latch / unlatch the subsea control pods and charge the subsea accumulators.**

Figure 2.8 presents hydraulic schematics of subsea control fluid circuit. The **hydraulic fluid** is **mixed, pressurized** and **stored in accumulator bottles** by the **hydraulic power unit.**

A **pilot operated accumulator isolator valve** is provided to allow the **pumps to charge the subsea accumulators.** When **control fluid** is used, it passes through a **totalizing flow meter** in the **hydraulic control manifold** and then through **the pod selector valve** which directs it to the chosen **subsea control pod.**

After passing through the **jumper hose** and the **subsea hose bundle** to the **control pod**, the fluid supplies the **hydraulically operated subsea regulators**. These reduce the fluid pressure to that required to operate the particular **BOP function** desired.

The fluid is also routed to the **SPM valve** in the pod which is controlled by the **accumulator isolator valve** on the **hydraulic control manifold.**

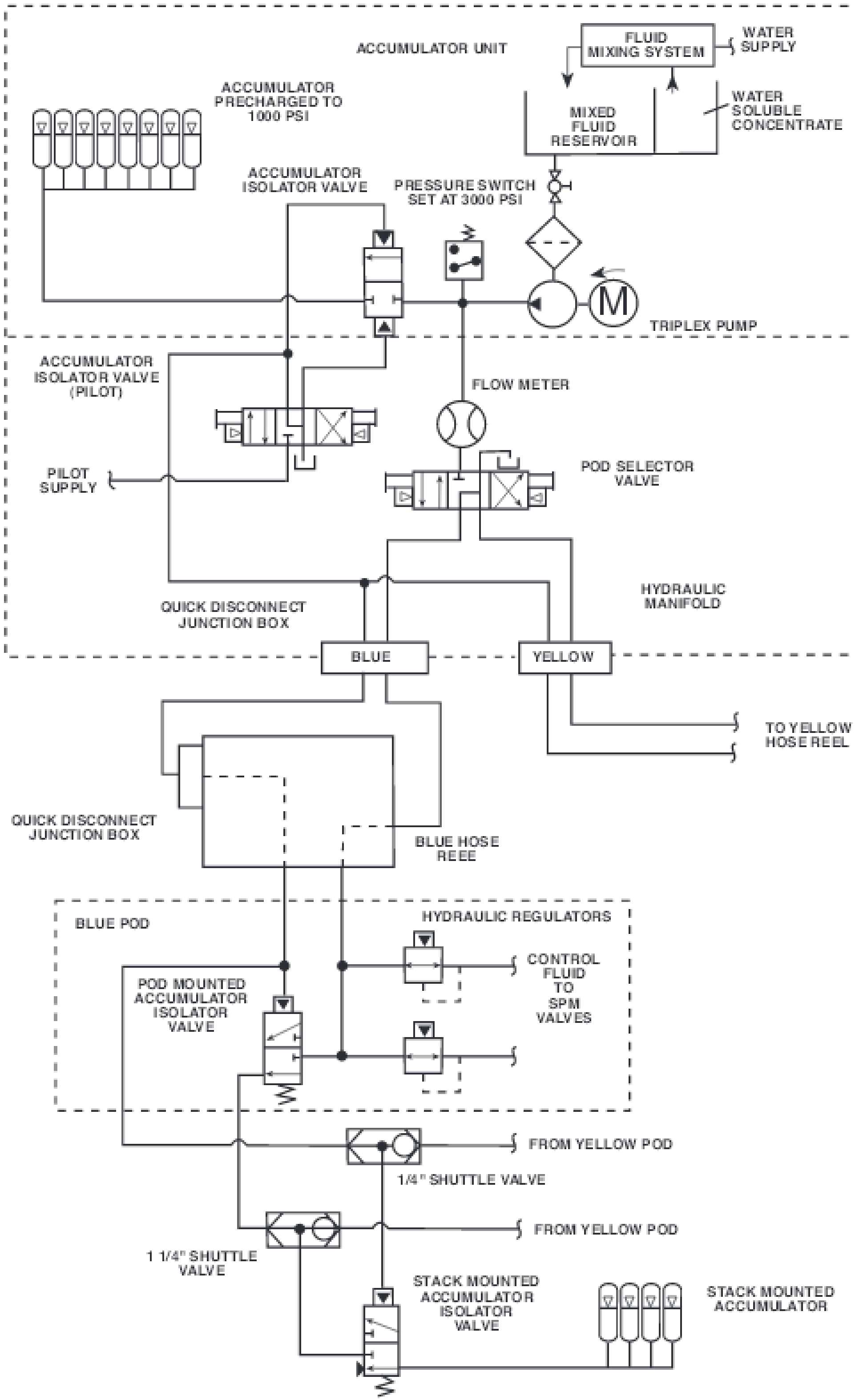


Figure 2.8:- Subsea Control System – Hydraulic Schematic

In the open position this **SPM valve** allows the **control fluid** to charge the **stack mounted accumulator bottles. Shuttle valves allow the bottles to be charged from either pod.**

The main components of the control system and some of the other operating sequences are now described in more details.

3.0 Hydraulic Power Unit

Hydraulic power unit (HPU) consists of (see fig. 2.8):

I. Mixing system
II. High pressure pumps
III. Accumulator banks

3.0.1 Mixing System

Hydraulic fluid is supplied to the entire control system from the hydraulic power unit. Hydraulic fluid is a combination of fresh water, soluble oil, glycol (for freeze protection), compressed air and electrical power for operation.

The soluble oil and glycol are stored in two small reservoirs and automatically blended with fresh water to make up the hydraulic fluid which is transferred and stored in large reservoir known as the mixed tank (see fig. 3.0).

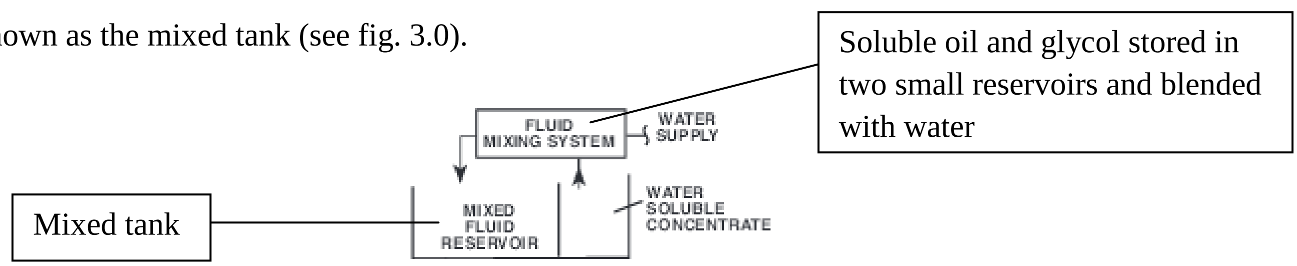


Figure 3.0:- Schematic of hydraulic fluid formulation

The used hydraulic power fluid is vented to sea due to space constraint and thus it is completely made biodegradable. Anti bacteria growth and corrosion control is added frequently in the mix water to control bacteria growth and inhibit.

The soluble oil reservoir has a capacity of at least 110 gal whilst the mix fluid tank should be capable of holding sufficient fluid to charge the system accumulators from there pre-charge condition to there maximum operating pressure. Most of the tanks are fitted with low level alarm systems which activates a warning light and horn on the control panels.

Air operated hydraulic pumps, a water pressure regulator, a double acting motor valve and a water flow rate indicator is used to keep the mixing fluid consistent.

The mixing pump is used to control the rate of water / additive concentration. A minimum rig water supply pressure of 25 psi is typically required for the correct operation of the mixing system and to provide a fluid supply at least equal to the rate at which mix fluid is drawn from the tank by the high pressure pumps.

3.0.2 High Pressure Pumps

The fluid is transferred from the mix tank and transferred to the accumulator bottles under pressure where it is ready for use by the high pressure pumps. Normally, there air powered and two electrically powered pumps are used. During normal operation the electric pumps are used to recharge the system. However, the air powered pump can assist if these cannot keep up with demand or fail in some way.

Most often the electric pump assembles are triplex reciprocating plunger pump with a chain and sprocket drive. The capacity of the pump should be such that the can charge the system accumulators from their pre-charge condition to the maximum operating pressure in less than 15 minutes

3.0.3 Accumulator Requirement

Accumulator requirements for subsea installation are the same for surface installation. The only difference is that more accumulator volume is normally required and some of the accumulator bottles is be mounted on the subsea blowout.

3.0.3.1 Volumetric Capacity

As a minimum requirement, closing units for subsea installations should be equipped with accumulator bottles with sufficient volumetric capacity to provide the usable fluid volume (with pumps inoperative) to close and open the ram preventers and one annular preventer. Usable fluid volume is defined as the volume of fluid recoverable from an accumulator between the accumulator operating pressure and 200 psi above the precharge pressure.

In sizing subsea mounted bottles, the additional precharge pressure required to offset the hydrostatic head of the sea-water column and the effect of subsea temperature should be considered.

3.0.3.2 Response Time

The closing system should be capable o closing each ram preventer within 45 seconds. Closing time should not exceed 60 seconds for annular preventers.

3.0.3.3 Requirement for Accumulator Valve

Multi–bottle accumulator banks should have valving for bank isolation. This isolation valves should have a rated working pressure at least equivalent to the designed working pressure of the system to which the are attached. The valves must be in open position except when the accumulators are isolated for servicing, testing or transporting.

3.0.3.4 Accumulator Types

Either separator or float type accumulators may be used.

3.0.3.4 Accumulator Tests

Accumulator Pre-Charge Pressure Test

This test should be conducted on each well prior to connecting the closing unit to the blowout preventer stack. Test should be conducted as follow:

a) Open the bottom valve on accumulator bottle and drain the hydraulic fluid into the closing unit fluid reservoir.
b) Measure the nitrogen precharge pressure on each accumulator bottle, using an accurate pressure guage attached to the precharge measuring port, and adjusts if necessary.

Accumulator Closing Test

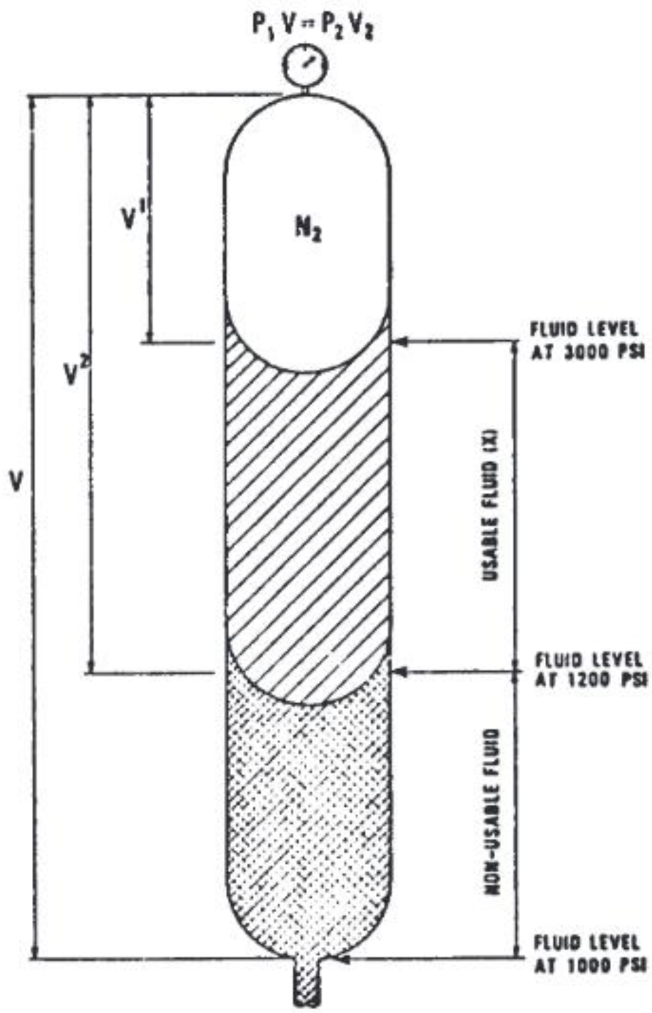
This test should be conducted on each well prior to pressure testing the blowout preventer stack. Test should be conducted as follows:

a) Position a joint of drill pipe in the blowout preventer stack.
b) Close off the power supply to the accumulator pumps.
c) Record the initial accumulator pressure. This pressure should be the designated operating pressure of the accumulators. Adjust the regulator to provide 1500 psi operating pressure to the annular preventer.
d) Simultaneously turn the control valves for the annular preventer and for one pipe ram (having the same size ram as the pipe used for testing) to the closing position and turn the control valve for the hydraulically operated valve to the opening position.
e) Record the time required for the accumulators to close the preventers and open the hydraulically operated valve. Record the final accumulator pressure (closing unit pressure). This final pressure should be at least 200 psi above the precharge pressure.
f) After the preventers have been opened, recharge the accumulator system to its designed operating pressure using the accumulator pumps.

3.0.3.5 Accumulator Sizing

Calculation of Accumulator Size

The volume of the accumulator system is calculated by using “Boyle’s Law”:



$P_1V_1 = P_2V_2$

Where

P_1 = Maximum pressure of the accumulator when completely charged.

P_2 = Minimum pressure left in accumulator after use. (Recommended minimum is 200 psi)

V = Total volume of accumulator (fluid and nitrogen)

V_1 = Nitrogen gas volume in accumulator at maximum pressure P_1

V_2 = Nitrogen gas volume in accumulator at minimum pressure P_2

$V_2 - V_1$ = Total usable fluid with safety factor usually 50% included.

Note:

3000 psi system pre-charge to 1000 psi; V = 3 V_1

Subsea Accumulators

The nitrogen precharge pressure must be increased in the subsea accumulator bottles in other to account for the hydrostatic pressure of the hydraulic fluid in the power fluid supply hose, when calculating the amount of usable fluid volume. As an added safety factor the sea water gradient is used for this purpose i.e. 0.445 psi / ft.

If operating in 1500 ft of water, the hydraulic pressure would be:

1500 ft x 0.445 psi / ft = 667.5 or 668 psi (rounded off)

Thus the nitrogen precharge pressure of 1668 psi (1000 psi + 668 psi)

Therefore:

P_1 = nitrogen precharge pressure of 1668 psi (1000 psi + 668 psi)

P_2 = minimum operating pressure of 1868 psi (1200 psi + 668 psi)

P_3 = maximum operating pressure of 3668 psi (3000 psi + 668 psi)

V_1 = bladder internal volume at precharge pressure (11 gal – 1gal)

V_2 = bladder internal volume at minimum operating pressure, P_2 (in gas)

V_3 = bladder internal volume at maximum operating pressure, P_2 (in gas)

Therefore:

1668 psi x 10 gals = 1868 psi x V_2

And

1668psi x 10 gal = 3668 psi x V_3

From the above calculation:

V_2 = 8.93 gal

V_3 = 4.55 gal

The usable volume of hydraulic fluid per subsea bottle in 1500 ft of water would be the difference between these two volumes.

[V_2 = 8.93 gal] – [V_3 = 4.55 gal] = [V = 4.38 gal]

4.0 Subsea Bop Control System Components

4.0.1 Regulator Control

The regulator control is used to regulate the power fluid from 3000 psi to 1500 psi as the BOP functions has a maximum normal operating pressure of 1500 psi . Two regulator controls are usually in the subsea control pod. One controls the ram preventer and the other annular preventer (see. Fig. 4.1).

From figure 3.1, a ½ “air operated pilot regulator in the control manifold transmits pilot pressure to the subsea regulator in order to adjust its setting. The air operator can be manipulated either manually using an air regulator on the control manifold or remotely from a remote panel. When operated from a remote panel a solenoid valve is used to increase the air pressure by allowing rig air to flow into a 1 gallon reservoir connected to the air pilot line. The receiver acts as a surge protector for the pilot regulator. Decreasing the air pressure is achieved by using a solenoid valve to vent the line to atmosphere.

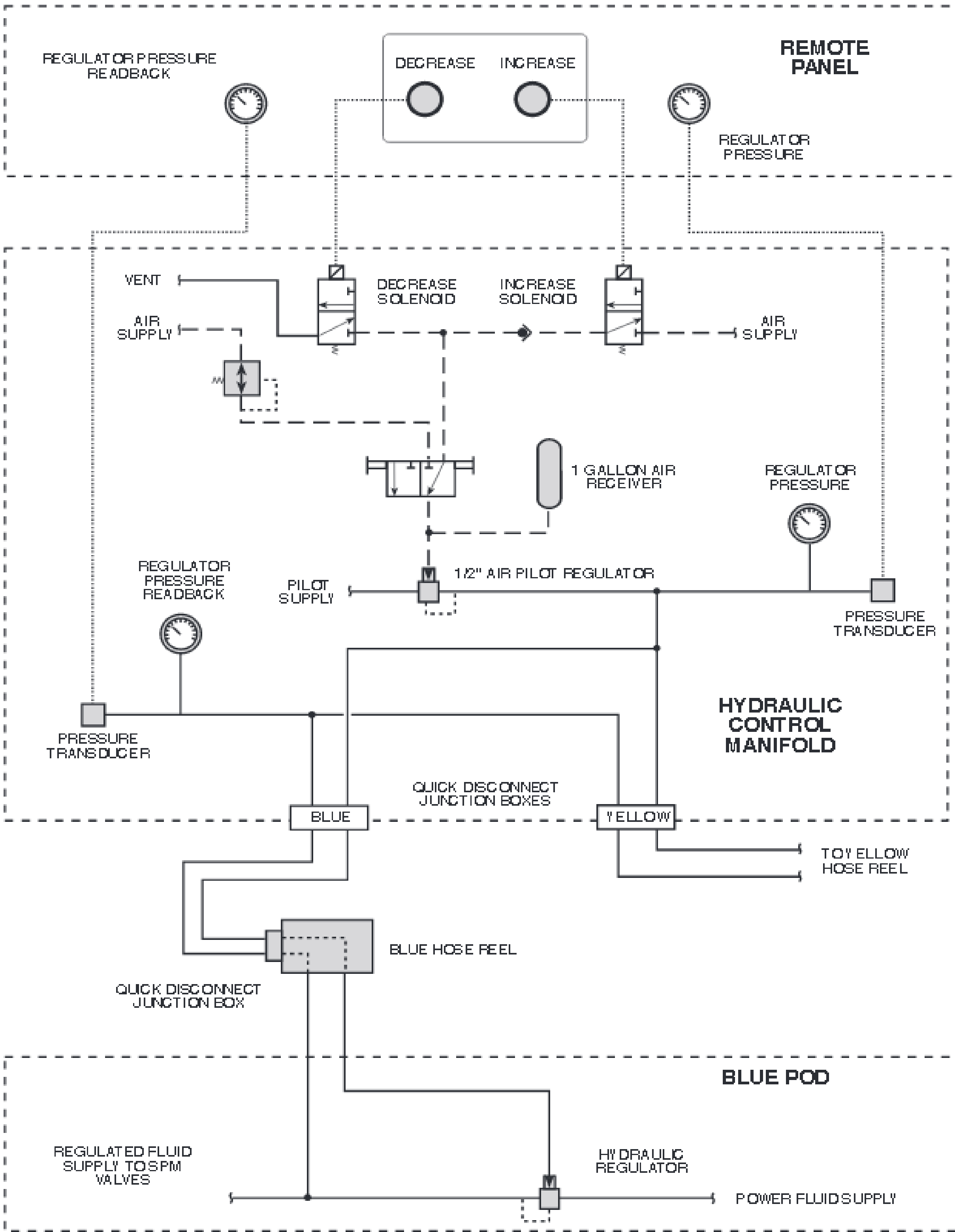


Figure 4.1:- Subsea Regulator Control Circuit

4.0.2 Pressure Readback

The read back system incorporated in the manifold ensures that the desired operating pressure is set by the subsea regulator (see Fig. 4.1). The output of each subsea regulator is connected through a 1/8 " hose in the umbilical back to a pressure guage in the control manifold. Pressure transducers transmit the readback pressures to remote panels. A shuttle valve also in the manifold unit connects the lines from both umbilicals and isolates the active and inactive pods.

All electrical components are housed in separate explosion proof housings on the control manifold unit. One housing contains the solenoid valves and another contains the transducers and pressure switches. The pressure switches are typically set to be activated "on" when pressure in the pilot line to the ram or failsafe SPM reaches 1000 psi and to switch ''off '' when the pressure falls below 700 psi.

4.0.3 Control Panel

Operation of the manifold unit from remote locations is through the control panel. Normally, two remote panels are used – a master one on the drill floor, and mini panel in a relatively safe location such as a rig office. Other mini panels can be integrated into the system if necessary.

The drillers master panel is normally explosion proofed or air-purged since it is located in a hazardous area. It contains a set of graphically arranged push-buttons indicating lights for operation and status indication of each stack function. The regulator pressures are controlled by increase / decrease push-buttons and there are gauges for monitoring pilot and readback values. A digital read back of the flow meter located on the control manifold is also provided.

Many types of driller's panel also include controls for the operation of the rig diverter system which is controlled in a similar way to a surface BOP system.

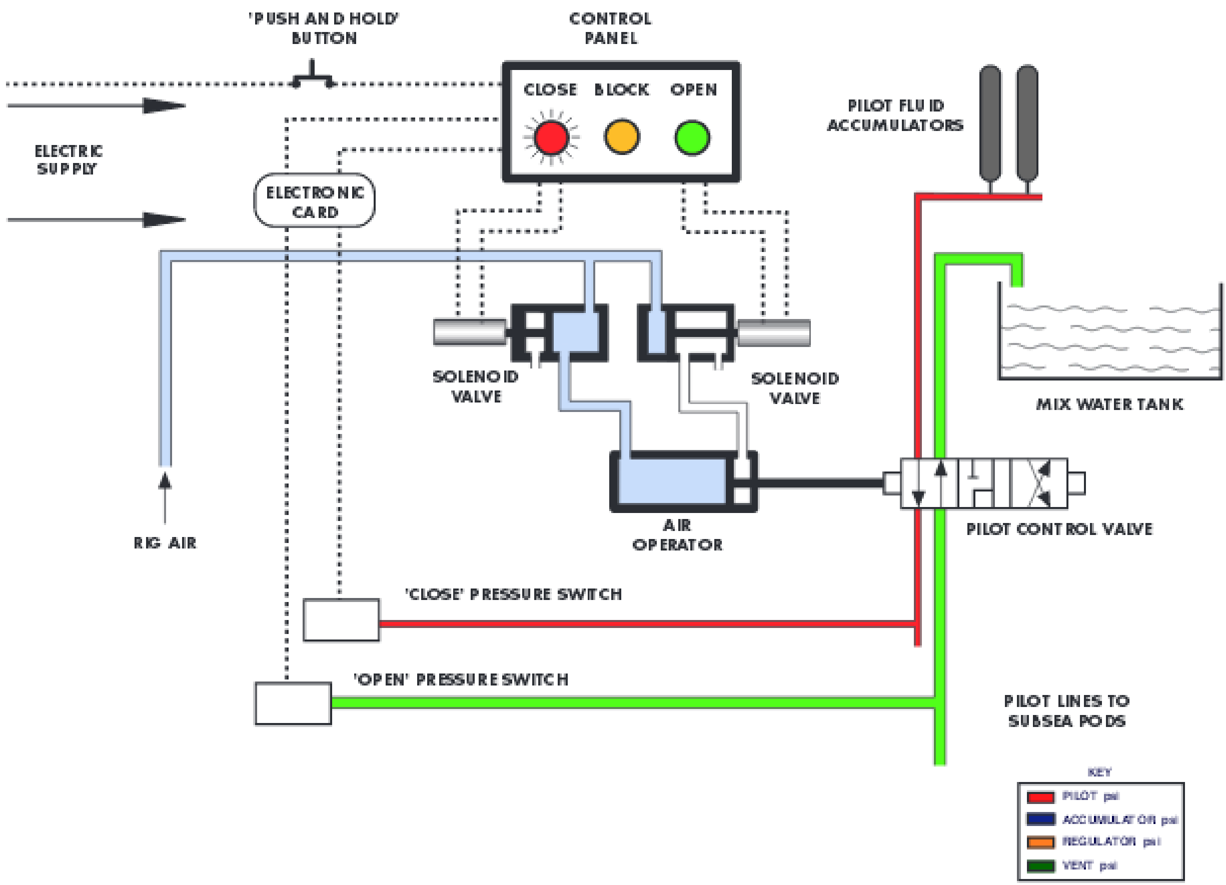
The mini panel is usually not required to be explosion proof. It operates in the same way as the master panel but does not include the pressure gauges. Both panels include ''lamp test'' facilities to check for burnt out lamps. They also contain alarms for low hydraulic fluid level, low accumulator pressure, low rig air pressure and an alarm to indicate that the emergency battery pack is in use.

The remote panel contains all the necessary electrical switches to operate the solenoid valves on the hydraulic control manifold which in turn control the air solenoid valves on the hydraulic control manifold which in turn control the air operators of the pilot control valves. Light on the panels (red, amber, green) indicates the position of the 3 position valve (open, block, close) and there is a memory system so that when a function is block with amber lights on, the actual position of the function (the red or green light) will also be displayed.

Figure 4.2 shows in more details the operation of a BOP function from a remote panel. Although the lights on the panels show the position of the BOP functions, the control button are not active until a push and hold button is depressed in order to allow the supply of electrical power to the panel. The sequence of event that occurs is as follows:

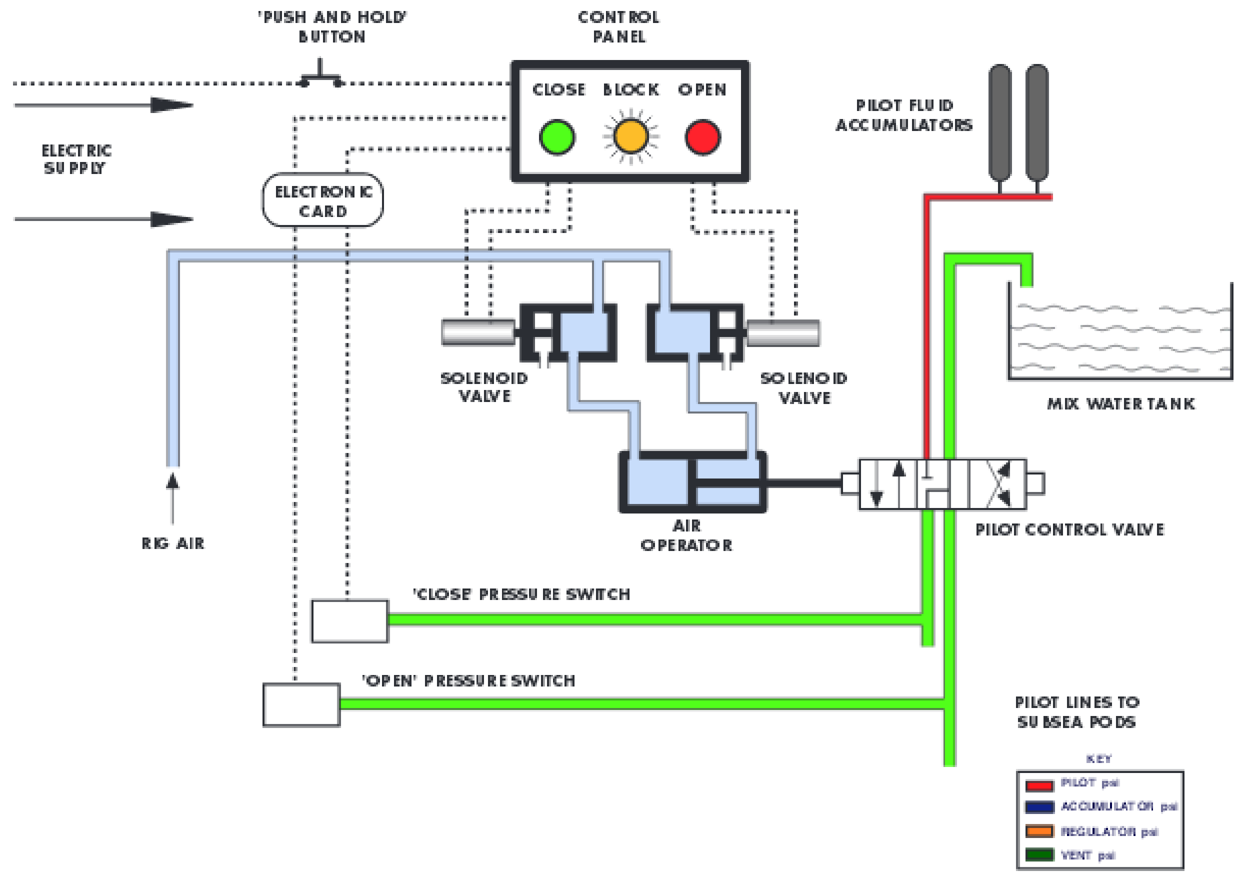
Close

I. The 'press' and ' hold' button is held in to activate the panel.
II. The 'close' button is pressed.
III. Currents flow to the 'close' solenoid valve which lifts to supply air to the 3-position air operator.
IV. The air operated piston moves the pilot control valve to the close position and pilot pressure is sent to the subsea control pod.
V. Successful pressurization of the pilot line to the control pod actuates a pressure switch on the control manifold.
VI. Current flows through an electronic card which illuminates the lamp of the close button indicating that the function is now closed.
VII. The press and hold button is released, the close lamp remains illuminated.



Block

- I. The press and hold button is held in to activate the panel.
- II. The block button is pressed.
- III. Current flows to the close and open solenoid valves which lift to supply air to both sides of the 3 position air operator piston.
- IV. The air operated piston moves to a central position which places the pilot control valve in the middle block position so that no pilot pressure is sent down either the close or open pilot line.
- V. Since no pilot line is pressurized, neither pressure switch is activated.
- VI. The electronic card senses that senses that no pressure switch has been operated and illuminates the block lamp.
- VII. The press and hold button is released, the block lamp remains illuminated.



Open

I. The press and hold button is held in to activate the panel.

II. The open button is pressed.

III. Current flows to the open solenoid valve which lifts to supply air to the 3 – position air operator.

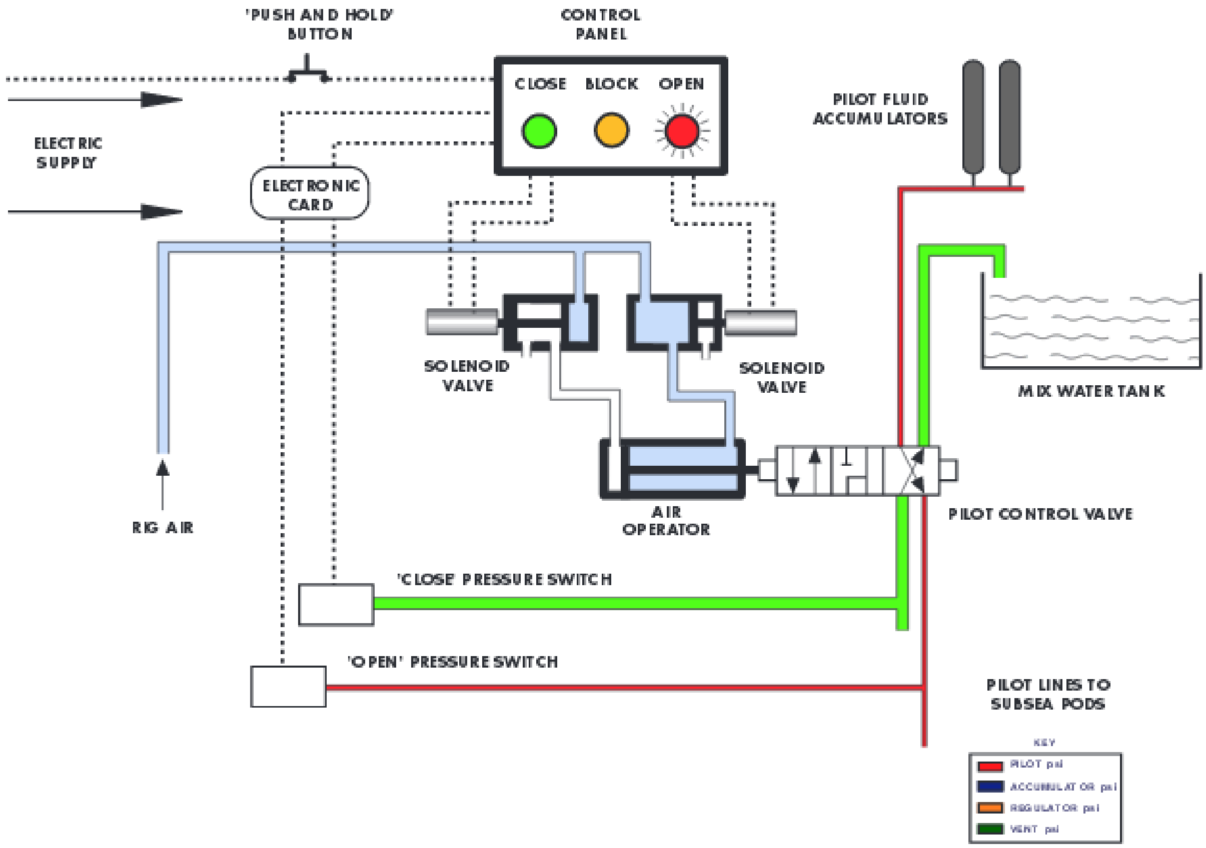
IV. The air operated piston moves the pilot control valve to the open position and pilot pressure is sent to the subsea control pod.

V. Successful pressurization of the pilot control valve to the open position and pilot pressure is sent to the subsea control pod.

VI. Successful pressurization of the pilot line to the control pod actuates a pressure switch on the control manifold.

VII. Current flows through an electronic card which illuminates the lamp of the open button and extinguishes the close lamp indicating that the function is now open.

VIII. The press and hold button is released, the open lamp remains illuminated.



Hydraulic leak is detected in the block position. This is achieved through systematically isolating the various BOP stack functions. It also used to depressurize the pilot lines when attaching junction boxes to the umbilical hose reels.

Note that the illumination of a push button lamp only indicates that a pilot pressure signal has been generated and not that a function has been successfully operated subsea**. Indications of a successful subsea function movements are:**

a. The flow meter shows that the correct amount of power fluid has been used.
b. There are fluctuations in manifold and readback pressure readings.
c. There is a noticeable drop in accumulator pressure.

The BOP function is designed to be controlled from any panel at any time during normal operations. If one panel or a cable to a panel is damaged, destroyed or malfunctions then it will not interfere with the operation of the system from any other panel.

An emergency battery pack supplies the electric panels with power for a period of up to 24 hours (depending on use) in case of failure of the rig supply. The power pack typically consists of ten 12 volts lead acid batteries in a fully charged condition ready for immediate use. Electrical cable connects the remote panels and the battery pack to the junction boxes on the hydraulic control manifold.

4.0.4 Hose Reels

The hose bundles are mounted on heavy duty reels for storage and handling. They are connected to the hydraulic control manifold by jumper hose. The reels are driven by reversible air motors and include a disc brake system to stop the reel in forward or reverse rotation.

During running or retrieving of the subsea control pod, the junction hose is disconnected from the hose reel. How ever in order to keep selected function 'live' while running or retrieving, five or six control stations are mounted on the side of the reel. These live functions include at least the riser and stack connectors, two pipe rams and the pod latch.

Once the BOP has landed and latched onto the wellhead, the control points on the side of the reel are shut down and isolated to prevent interference with the full control system. The regulators on the reel which control the manifold and annular pressures must also be isolated in case they dump pressure when the jumper hose RBQ plate is attached.

With the supply pressure isolated the 3 position, 4 way valves are used to vent any pressure that may remain trapped in a pilot line holding an SPM valve open. This is necessary since the reel is lifted with a different type valve to the control manifold manipulator valves. These valves look similar but do not vent when placed in the block position.

4.0.5 Umbilical Hose

The umbilical transmits all power fluid and all pilot signals from surface to the subsea control pods. Hydraulic pressure from the regulated side of the subsea regulators is also transmitted through the umbilical to pressure read back gauges at surface. The power fluid is supplied only to the umbilical of the selected active and inactive pods. The most common umbilicals contain 1" ID supply hose for the power fluid which is surrounded by up to sixty four 1/8" and 3/16" hoses for pilot valve activation and readbacks. An outer polyurethane covering protects the whole bundle.

Roller sheaves are used to support the umbilical and provide smooth and safe handling where it leaves the hose reel and goes over the moon pool area. Special clamps are used to attach the hose bundle to the pod wireline at intervals that correspond to the lengths of riser in use.

4.0.6 Subsea Control Pod

The subsea control pod contains the equipment that provides the actual fluid transfer from the hose bundle to the subsea stack. A typical pod assembly consists of 3 selections:

I. A retrievable valve block
II. An upper female receptacle block permanently attached to the lower marine riser package.
III. A lower female receptacle permanently attached to the BOP stack.

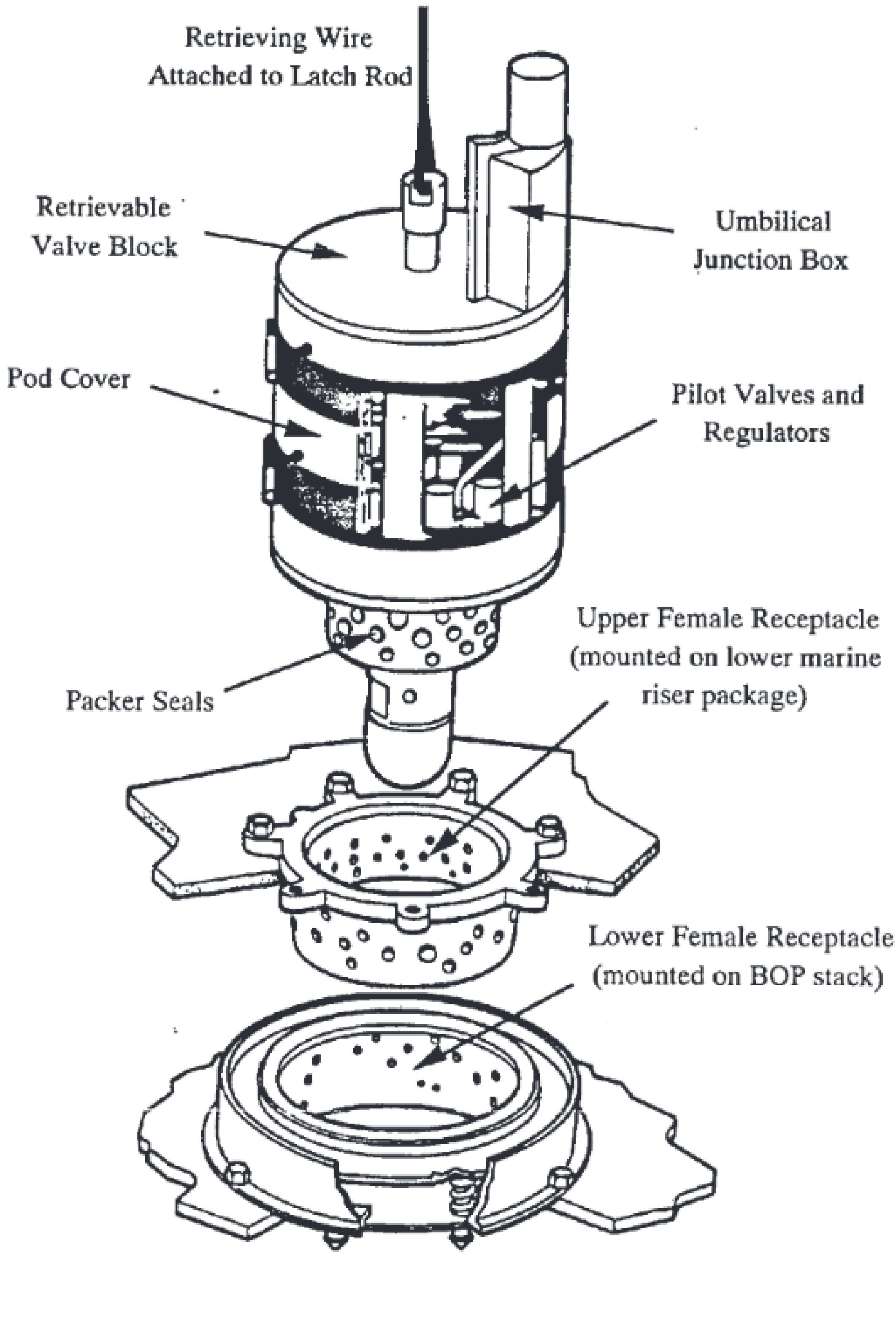


Figure 4.2:- Subsea Control Pod

Control fluid enters the pod at the junction box and routed direct to an SPM valve or to one of the two regulators (one of the BOP rams and one for the annular preventers) from where it is sent to the appropriate SPM.

When a SPM pilot valve is actuated it allows the control fluid to pass through it to the exit ports on the lower part of the male stab and into the female receptacle attached to the lower marine riser package.

For those functions which are part of the lower marine riser package the fluid is then routed out of the upper female receptacle and directed via a shuttle valve to the functions operating piston. For those function which are part of the main BOP stack, the fluid is routed through the upper female receptacle and into the lower female receptacle from where it goes via a shuttle valve to the appropriate operating piston.

Note:

Not all functions on the BOP stack are controlled through pod mounted pilot valves. Low volume functions such as ball joint pressure are actuated directly from surface through ¼" lines. These are generally referred to as straight through functions.

The integrity of each fluid route between the different sections is achieved by using a compression seal that is installed in the retrievable valve block section of the pod. Compression between the three section is achieved by hydraulically locking the pod into the lower receptacle (which is spring mounted on the BOP stack in order to facilitate easier engagement).

Locking is accomplished by hydraulically extending two dogs that is located under the bottom of the upper female receptacle. A helical groove on the outside of the lower skirt of the pod ensures correct alignment of the fluid ports. To retrieve the pod independently of the lower marine riser package, the locking pressure is bled off and the dogs are retracted mechanically when an overpull is taken on the retrieving wire.

A more recent design utilizes the same concept but consists of a cube shaped retrievable valve block which latches over two tapered blocks mounted on a base plate permanently attached to the BOP stack. The packer seals on the retrievable valve block are pressure balance in a breakaway condition so that there is no tendency for it to be blown out of the pocket if the pod has to be released under pressure.

Besides the latching system, packer seals and piping, the principal components of the retrievable valve blocks are the SPM pilot valves and regulators.

4.0.7 SPM Valves

As discussed above, these valves direct the regulated power fluid to the desired side of the preventer, valve or connector operating piston and vent the fluid from the other side of the piston to the sea. The annular preventers typically use large 1 ½" SPM valves in order to provide sufficient fluid flow, the ram preventers use 1" valves and the other functions such as failsafe valves and connectors use ¾" valves. An illustration below is NL Shaffer 1 in SPM valve (see Fig.4.3).

The valve is a poppet type in which a sliding piston seals at the top and bottom of its travel on nylon seats. In the normally closed position a spring attached to the top of the piston shaft keeps the piston on the bottom seat and prevents the power fluid from passing through the valve to the exit port. Power fluid pressure, which is permanently present, also assists in keeping the valve closed by acting on a small piston area on the spindle. In this position fluid from the valve's associated operating piston is vented through the sliding piston at ambient conditions.

When pilot pressure is applied to the valve the sliding piston moves up and seals against the upper seat which blocks the vent ports and allows regulated power to flow through the bottom section of the valve to the exit port. Power fluid pressure, which is permanently present, also assists in keeping the valve closed by acting on a small piston area on the spindle. In this position fluid from the valve's associated operating piston is vented through the sliding piston at ambient conditions.

When pilot pressure is applied to the valve the sliding piston moves up and seals against the upper seat which blocks the vent ports and allows regulated power fluid to flow though the bottom section of the valve to function the BOP.

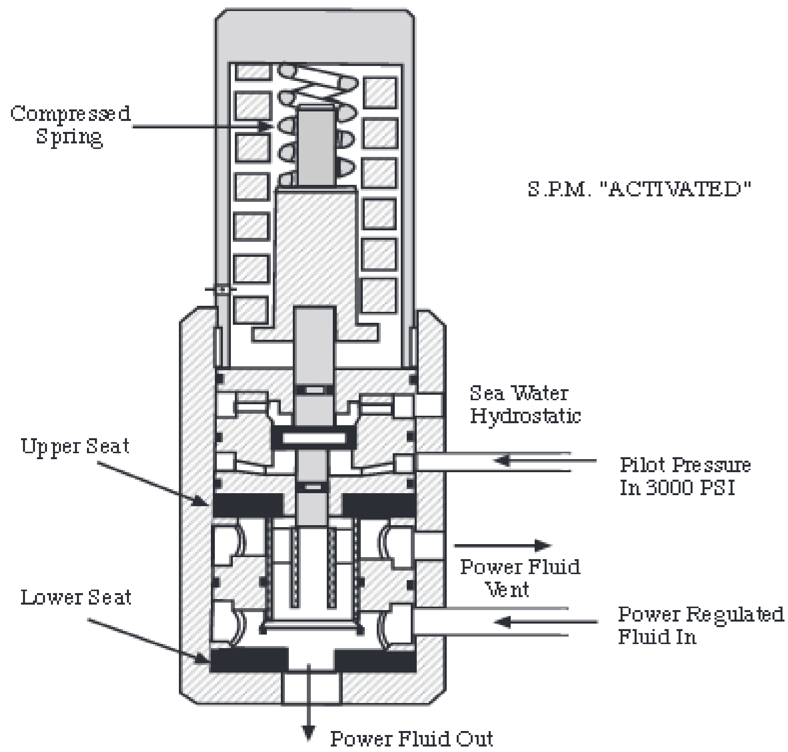


Figure 4.3:- NL SHAFFER 1" SPM VALVE

Note:

The pilot fluid therefore operates in a closed system whilst the hydraulic power or control fluid is an ''open'' circuit with all used fluid being vented to the sea.

4.0.8 Regulators

The both control pods contains two regulators each. One for regulating pressure for the ram preventers and the other for regulating pressure for operating the annular preventer. Some control systems incorporate a third regulator so that the operating pressure of each annular preventer can be individually manipulated.

Typical regulators are 1 ½ " hydraulically operated, stainless steel, regulating and reducing valves. Referring to figure 4.1 above, the output line of each regulator is tapped and the pressure roused back to a surface guage through the umbilical. This readback pressure is used to confirm that the subsea regulator is supplying the power fluid at the pressure set by the pilot surface regulator.

4.0.9 Redundancy

The two subsea control pods are functionally identical. When a pilot control valve (ram close for example) is operated on the hydraulic control manifold a pilot signal is sent down both umbilicals so that the associated SPM valve in each pod fires. If the pod selector valve is set on yellow then power fluid is sent only to this pod and it is only through the SPM valve in this pod that the fluid will reach the ram operating piston. The pod selector has no effect on the pilot system.

Once the yellow pod SPM valve fires, the power fluid passes through it to a shuttle valve, the shuttle piston of which moves across and seals against the blue pod inlet. The fluid then passes through the shuttle valve to move the ram to the close position. Fluid from the opposite side of the operating piston is forced out through the 'ram open' shuttle valve and vented through the 'ram open' SPM valve and into the sea.

Note:

If the blue pod was now selected to open the rams; then the power fluid would flow to the ram through the 'open' SPM on the blue pod but the fluid from the close side of the piston would be vented through the yellow pod SPM since the 'close' shuttle piston would still be sealing the blue pod inlet port.

The shuttle valve should be located as near as possible to their relevant ports on the BOP stack since the system is redundant only down as far as the shuttle valves.

5.0 Trouble Shooting

Locating a fluid leak or a malfunction of the subsea control system requires a very thorough knowledge of the equipment and a systematic approach to trace the source of the problem. Subsea control systems are very complex in there details and there are always minor variations and modifications even between similar models therefore trouble shooting should always be carried out with reference to the relevant schematics.

5.0.1 Leaks

A fluid leak is usually detected by watching the flow meter. A leak is indicated if a flow is indicated when no function is being operated or if the flow meter continues to run and does not stop after a function has been operated then a leak in the system is implied. The following steps can be used to detect and locate its source:

5.0.1.1 Check the Surface Equipment

I. Examine the hydraulic control manifold for a broken line or fitting.
II. Examine the accumulator bottles for signs of a fluid leak.
III. Check the jumper hoses for signs of damage
IV. Check the hose reels and junction boxes for loose connections.
V. Confirm that the shut-off valve to the reel manifold pressure supply is tightly closed (if this is left open when the junction box is connected to the reel, it will allow fluid pressure to be forced back through one of the surface regulators and vent into the mix water tank thus indicating a leak.

Note:

If this fails to locate the source of the leak then return to the hydraulic control manifold for an item by item check of the system.

Use the Pod Selector Valve to Operate the System on the Other Pod

I. If the leak does not stop then it must be located either in the hydraulic control manifold or downstream of the subsea control pods.

II. If the leak does stop then it will be known which side of the system it is in.

Further checks would then be as follows:

If the leak stops-

a) Assuming condition permits, switch back to the original pod and block each function in turn (allow plenty of time for the function to operate and check the flow meter on each operation).
b) If the leak stops when a particular function is set to block then the leak has been isolated and it is somewhere in that specific function.
c) In this case run the subsea TV to observe the pod whilst unblocking the function.
d) If the leak is coming from the pod it will be seen as a white mist in the water and a bad SPM valve or regulator can be assumed and options are:
    - Pull the pod to repair the faulty component.
    - Leave the function in block until the stack or lower marine riser package is retrieved.
e) If the leak is seen to be coming from below the pod then the options are:
    - Attempt repair using divers.
    - Leave the function in block until the stack is brought to surface.
f) If the leak does not stop:-
    - Check the return line to the mix water tank (if there is fluid flowing from this line then there is a leaking control valve or regulator)
    - Check that all the control valve are in either the open closed or block position (a partially open valve can allow fluid to leak pass it)
    - If the valve positions are correct then disconnect the discharge line from each valve – one at a time (fluid flow from a discharge line indicates a faulty valve)

- If the discharge lines do not show any signs of a leak then disconnect the discharge lines from the regulators in the same way.

It can sometimes be the case that the system is operating normally until a particular function is operated and the flow meter continuous to run after the time normally required for that function to operate. In this case there is a leak in that function with a likely reason being foreign material in the SPM valve not allowing the seat to seal thus causing the system to leak hydraulic fluid.

A possible remedy might be to operate the valve several times to try and wash out the foreign material. Observe the flowmeter to see if the leak stops. If the leak still persists then it will be a case of running the subsea TV to try and locate the leak visually.

5.0.2 Malfunctions

Typical control system malfunctions are slow reaction times or no flowmeter indication when a button is pressed to operate a function. A slow reaction time could be due to:

I. Low accumulator pressure
II. A bad connection between the jumper hose and hose reel
III. A partially plugged pilot line

In this case the trouble shooting would be:

5.0.2.1 Check the Pressure

I. Verify that the gauges are indicating the correct operating pressures
II. If a low pressure is indicated then verify correct operation of the high pressure pumps and check the level of hydraulic fluid in the mix water tank
III. Check that the shut off valve between the accumulators and the hydraulic control manifold is fully open

5.0.2.2 Check the Hoses

I. If the pressures are good then check all the surface hose connections

II. Check the junction box connections (if they are not tightly seated, the flow rate through the connection can be restricted and cause the function to operate slowly.

5.0.2.3 Check the Pilot Lines

I. If the above checks fail to locate the problem then the final option will be to retrieve the pod and check the pilot line for any sludge that may have settled out from the hydraulic fluid (disconnect each pilot line from the pod one at a time and flush clean fluid through it).

In the situation where there is no flowmeter indication when a function button is pressed, this could be due to:-

- The control valve on the hydraulic manifold did not shift
- The flowmeter is not working properly
- There is a plugged pilot line or faulty SPM valve

5.0.2.4 Check the Pressures

- Verify that the gauges are indicating the correct operating pressures
- If a low pressure is indicated then verify correct operation of the high pressure pumps and check the level of hydraulic fluid in the mix water tank.
- Check for correct operation of the pressure switches
- Check the fluid filters to make certain they are not plugged
- Check the accumulator precharge pressures
- Bleed the fluid from the bottle back into the tank and check the nitrogen pressure in each bottle

5.0.2.5 Check the Hydraulic Control Manifold

- Use the 'test' button on the control panel to make certain that the position lamps are not burnt out

Check the air and electrical supply to the hydraulic control manifold:-

- ✓ Check the electrical circuits to the control panel and also the solenoid valves and power relays.
- ✓ If the air supply pressure is sufficient to work the control valve operator check for an obstruction to the manual control handle
- ✓ If the valve can be easily operated manually then replace the entire valve assembly with a valve known to be in good working order.

5.0.2.6 Check the Flowmeter

- If the regulator pressure drops by 300 to 500 psi when the function is operated and then returns to normal, the function is probably working correctly and the flowmeter is faulty.
- Monitor the flowmeter on the hydraulic manifold to verify that the one on the drillers panel is not at fault (the impulse unit that sends the flowmeter signal to the panel could malfunction).

Section B – Marine Riser System

6.0 Marine Riser Systems

A marine riser system is used to provide a return fluid flow path from the wellbore to either a floating drilling vessel (semi submersible or hull type) or a bottom supported unit, and to guild the drilling string and tools to the wellhead on the ocean floor (see Fig. 6.0). Components of this system include:

- ✓ Remotely operated connectors
- ✓ Flexible joint (ball joint)
- ✓ Riser sections
- ✓ Telescopic joints
- ✓ Tensioners

Figure 6.0:- Marine Riser System

Data on these components, together with information on handling and care of the riser, are included in this section, *API RP 2Q: Recommended Practice for Care and use of Marine Drilling Risers and API RP 2Q: Recommended Practice for design and Operation of Marine Drilling Riser Systems.*

For a drilling vessel, the marine riser system should have adequate strength to withstand:

a) Dynamic loads while running and pulling the blowout preventer stack
b) Lateral forces from currents and acceptable vessel displacement
c) Cyclic forces from wave and vessel movement
d) Axial loads from the riser weight, drilling fluid weight, and any free standing pipe within the riser; and
e) Axial tension from the riser tensioning system at the surface (which may be some what cyclic) or from buoyancy modules attached to the exteriors of the riser.

Note:-

Internal pressure rating of the marine riser system (pipe, connectors, and flexible joint) should be at least equal to the working pressure of the diverter system plus the maximum difference in hydrostatic pressures of the drilling fluid and sea water at the ocean floor.

In deeper waters, riser collapse resistance, in addition to internal pressure rating, may be consideration if circulation is lost or riser is disconnected while full of drilling fluid.

For bottom-supported units, consideration should be given to similar forces and loads with the exception of vessel displacement, and high axial loads. Operating water depths for bottom supported units are often shallow enough to permit free standing risers to be used without exceeding critical buckling limits, with only lateral support at the surface and minimal tension being required to provide a satisfactory installation.

Note:

Information presented in this section applies primarily to floating drilling vessels, since more demanding conditions normally exists for these marine riser systems than for those installed for bottom – supported units.

6.1 Marine Riser Components

Additional details are contained in API RP 2K: Recommended Practice for Care and Use of Marine Drilling Risers and API RP 2Q: Recommended Practice for Design and Operation of Marine Drilling Riser Systems.)

6.1.1 Remote Operated Connector

A remote operated connector (hydraulic actuated) connects the riser pipe to the blowout preventer stack and can also be used as an emergency disconnect from the preventer stacks, should condition warrant. The internal diameter of the connector should be al least equal to the internal bore of the blowout preventer stack. Its pressure rating can be equal to either the components of the riser system (connectors, flexible joint etc.) or to the rated working pressure of the blowout preventer stack (in case special conditions requires subsequent installation of additional preventers on top of the original preventer stack). Connectors with the lower pressure rating are designated C_L while does rated at the preventer stack working pressure are designated C_H. Additional factors to be considered in selection of the proper connector should include ease and reliability of engagement / disengagement, angular misalignments, and mechanical strength.

Engagement or disengagement of connector with the mating hub should be an operation that can be repeatedly accomplished with ease; even for those conditions here some degree misalignment exists.

Mechanical strength of connectors should be sufficient to safely resist loads that might reasonable be anticipated during operations. This would include tension and compression loads during installation, and tension and bending forces during both normal operations and possible emergency situations.

6.1.2 Marine Riser Flexible Joint (Ball Joint)

A flexible joint is used in the marine riser system to minimize bending moments, stress concentrations, and problems of misalignment engagement. The angular freedom of a flexible joint is normally 10 degrees from vertical. A flexible joint is always installed at the bottom of the riser system either immediately above the remotely operated connector normally used for connecting / disconnecting the riser from the blowout preventer stack, or above the annular preventer when the annular preventer is placed above the remotely operated connector (see Fig. 6.1).

Figure 6.1:- Riser Flexible Joint

For those vessels having a diverter system, a second flexible joint is sometimes installed between the telescopic joint and the diverter to obtain required flexibility, or some type of gimbal arrangement may also be used. For deepwater operations or unusually severe sea conditions, another flexible joint may be installed immediately below the telescopic joint.

Mechanical strength required for the flexible joints are similar to those for the remotely operated connector. They should be capable of safely withstanding loads that might reasonably be encountered during operations, both normal and emergency. In addition, the angular freedom of approximately 10 degree should be accomplished with minimum resistance while the joint is under full anticipated load. Hydraulic ‘’pressure balancing’’ is recommended for ball-type flexible joints to counteract unbalanced forces of tensile load, drilling fluid density and sea water density. This pressure balancing also provides lubrication for flexible joints.

It is technically important to monitor the flexible joint angle during operation, so as to maintain it at a minimum. One method of assessing this is by the use of angle-azimuth indicator. The flexible joint angle, vessel offset, and applied (riser) tension are indicators of stress levels in the riser section. For continuous drilling operations, the flexible joint should be maintained as straight as possible, normally at an angle of less than 3 degree: greater angle cause undue wear or damage to the drill string, riser, blowout preventers, wellhead or casing. For riser survival (i.e. to prevent over stressing) the maximum angle will vary from about 5 degrees to something less than 11 degrees, depending upon parameters such as water depth, vessel offset, applied tension, and environmental conditions. Drill pipe survival must also be considered if the pipe is in use during those critical times of riser survival conditions.

6.1.3 Marine Riser Sections

(Refer to API RP 2Q: Recommended Practice for Design and Operation of Marine Drilling Riser Systems for additional details).*

Specifications for riser pipe depend upon service conditions. It should be noted, however, that drilling vessel normally encounter a wide variety of environments during their service life; consequently, the riser should have a minimum yield strength and fatigue characteristics well in excess of those required not only for the present but for reasonable anticipated future conditions.

Figure 6.2:- Marine Riser Joints

Riser pipe steels should confirm to *ASTM Designation A-530: General Requirements for Specialized Carbon and Alloy Pipe Steel* and be fabricated and inspected in accordance with *APL Spec 5L: Specification for Line Pipe.* Specifications that provide riser pipe with a reasonable service life for operation in most parts of the world include steel having minimum yield strength of between 50,000 psi and 80,000 psi. Risers with lower minimum yield strength (35,000 psi) have proven satisfactory if used in those areas where only light to moderate service conditions are encountered.

The internal diameter of the riser pipe is determined by size of the blowout preventer stack and the wellhead, with adequate clearances being necessary for running drilling assemblies, casing and accessories, hangers, pack off unit, wear bushings, etc.

Marine riser connectors should provide a joint having strength equal to or greater than that of the riser pipe. For severe service, quench and tempering and shotpeening the connector pin end are sometimes done. The joint, when made up and tested under reasonable maximum anticipated service loads, should have essentially no lateral, vertical, or rotational movement. After release of load, the joint should be free of deformation, galling or irregularities. Make-up practice including bolt-torque requirement, should be specified by the manufacturer.

Auxillary drilling fluid circulation lines are sometimes required and included as an integral part of large diameter riser systems. Drilling fluid can be pumped into the lower section of the riser system to maintain adequate annular velocities while drilling small diameter holes. The number of lines, size, and pressure rating will be determined by flow rates and pressure required.

6.1.4 Marine Riser Telescopic Joint

The telescopic joint serves as a connection between the marine riser and the drilling vessel, compensating principally for heave of the vessel. It consists of two main sections, the outer barrel (lower member) and the inner barrel (upper member).

The outer barrel (lower member), connected to the riser pipe and remaining fixed with respect to the ocean floor, is attached to the riser tensioning system and also provides connections for the kill and choke lines. A pneumatically or hydraulically actuated resilient packing element contained in the upper portion of the outer barrel provides a seal around the outside diameter of the inner barrel.

The inner barrel (upper member), which reciprocates within the outer barrel, is connected to and moves with the drilling vessel and has an internal diameter compatible with other components of the marine riser system. The top portion of the inner barrel has either a drilling fluid return line or diverter system attached, and is connected to the underneath side of the rig sub structure.

The telescopic joint, either in the extended or contracted position, should be capable of supporting anticipated dynamic loads while running or pulling the blowout preventer stack or should have sufficient strength to safely resist stress that might reasonably be anticipated during operations. Stroke length of the inner barrel should provide a margin of safety over and above the maximum established operating limits of heave for the vessel due to wave and tidal action.

Selection of a telescopic joint should include consideration of such factors such as size and stroke length, mechanical strength, packing element life, ease of packing replacement with the telescopic joint in service, and efficiency in attachment of appurtenances (i.e. tensioner cables, choke and kill lines, diverter systems etc.)

6.1.5 Marine Riser Tensioning System

The marine riser tensioning system provides for maintaining positive tension on the marine riser to compensate for vessel movement. The system consists of the following major components:

a) Tension cylinders and sheave assembly,
b) Hydro pneumatic accumulators / air pressure vessels,
c) Control panel and manifolding,
d) High pressure air compressor units, and
e) Standby air pressure vessels.

Tensioning at the top of the riser is one of the more important aspects of the riser system, as it attempts to maintain the riser profile as nearly straight as practicable and reduce stresses due to bending. As tension is increased, axial stress in the riser also increases. Therefore, an optimum tension exists for a specific set of operating conditions (water depth, current, riser weight, drilling fluid density, vessel offset etc.).

Wireline from the multiple hydraulic tensioner cylinders are connected to the outer barrel of the telescopic joint. These cylinders are energized by high pressure air stored in the pressure vessels. Tension on the wireline is directly proportional to the pressure of stored air. In general, as the vessel heaves upward, fluid is forced out of the hydraulic cylinders thereby compressing air. As the vessel heaves downward pressure of the compressed air will cause the hydraulic cylinders to stroke in the opposite direction.

Selection of tensioners should be based on load rating, stroke length, speed of response, service life, maintenance cost and ease of service. Maximum load rating of individual tensioners depends on the manufacturer, typically ranging from 45,000 to 80,000 pounds and allowing maximum vertical vessel motion of 30 to 50 ft. Design of the wireline system that supports the riser must take into consideration the angle between the wireline and the axis of the telescopic joint and its influence on stresses.

The number of tensioners required for a specific operation will depend on such factors as riser size and length, drilling fluid density, weight of suspended pipe inside the riser, ocean currents, vessel offset, wave height and period and vessel motion. Computer Programmes are available for riser analysis, including tensioning requirements. Consideration should also be given to operating difficulties that might occur should one of the tensioners experience wireline failure. Recommendations for marine riser design and operation of the tensioning systems are contained in *API RP 2K: Recommeded Practice for Care and Use of marine Drilling Risers and API RP 2Q: Recommeded Practice for Design and Operation of Marine Drilling Riser System.*

Periodic examination of riser tensioning system units should be made while in service, since the system can cycle approximately 6000 times per day. Particular care should be taken to establish a wireline slipping and replacement program based on ton cycle life for the particular rig installation.

6.1.6 Bouyancy

For deeper and ultra deep waters it will be impractical from an operating point of view to install sufficient units capable of providing adequate tensioning. In these cases, some types of riser buoyancy may be the solution (flotation jackets, buoyancy tanks, etc.) Bouyancy reduces the top tensioning requirements but loses some of its effectiveness as a result of the increased riser diameters exposing a greater cross sectional area to wave forces and ocean currents. Selection of the optimum method and / or material for obtaining buoyancy requires careful consideration of a number of factors, including water adsorption, pressure integrity, maintenance requirements, abuse resistance, and manufacturer quality control. Several of these factors are time and water depth dependent. As water depth increases, these factors become more critical. A part of any analysis for an optimum safe system should include considerations of the consequences of buoyancy failure during operations.

6.1.7 Riser Running and Handling

Closed supervision and well trained crews are needed for maximum efficiency and to preclude any failure from improper handling or make-up of marine riser connectors. Some special equipment and tools for handling, running, and make up / break out may also be beneficial, both in protecting the riser and improving efficiency. These tools include a flare end guide tube for guiding the riser through the rotary table and a joint lay down trough installed in the V-door. Care should also be taken in protecting riser joints stored on the vessel.

6.2 Marine Riser Inspection and Maintenance

As marine riser joints are removed from service, each joint and connector should be cleaned, surfaces visually inspected for wear and damage, damaged packing or seals replaced and surface re-lubricated as required. Bouyancy material and or systems if installed, should also receive close inspection. Prior to running a riser through inspections of all components may also be warranted, particularly if the riser has been idle for sometime or previous inspection procedures are unknown. For those operations where environmental forces are severe and or tensioning requirements are high, consideration should be given to maintaining records of individual riser joint placement in the riser string and periodic testing (non destructive testing) of the connector and critical weld areas to reduce failures. *Refer to API RP2K: Recommeded Practice for Care and Use of Marine Drilling Risers for specific information.*

Section C – Testing of BOP System

7.0 Testing Periods

Pressure test on the well control equipment should be conducted at least once every 21 days.

1. **After setting casing.**
2. **Prior to entering a known transition zone.**
3. **After B.O.P repairs or change.**

NB: In addition to this, prior to spud and upon installation. Also after the disconnection or repair of any pressure containment seal in the BOP stack, choke line or choke manifold but limited to the affected component.

Initial test should be the lesser of the rated working pressure of the stack wellhead upper part of the CSG.

Low Pressure Testing i.e. Diverter System = 200 – 300 psi

7.1 Testing During Operation

Stack should be tested to at least 70% of its rated working pressure but limited to the lesser of the rated working pressure of the wellhead or 70% of the minimum internal yield of the upper part of the CSG string.

Annular – Tested to 70% API RP 53 of its rated working pressure.

Company policy might dictate that annular be tested to 50% of working rate to prevent excessive wear.

Choke Manifold, V/VS safety etc, same as stack test.

On stump tested to rated working pressure.

Factory tested to 150% of rated working pressure.

7.2 A.P.I. Regulations On Closing Units

Surface:

I. Minimum Requirements: All surface closing units should be equipped w / sufficient volumetric capacity to provide the useable fluid volume (w / pumps isolated) to close 1 Pipe Ram, 1 Annular & open the Hyd. Choke valve.

II. Accumulator Response Time: Response time between activation and complete operation of a function is based on BOP or valve closure and seal off.

For surface installations, the BOP control system should be capable of closing each ram BOP within 30 seconds. Closing time should not exceed 30 seconds for annular BOPs smaller than 18 ¾ inches nominal bore and 45 seconds for annular preventers of 18 ¾ nominal bore and larger. Response time for choke and kill valves (either open or close) should not exceed the minimum observed ram close response time.

For subsea installations, the BOP control system should be capable of closing each Ram preventer within 45 secs and Subsea closing unit for annular preventer should not exceed 60 secs for Annular Preventer.

III. Pump Capacity: with the accumulator isolated, the pump should be capable of closing annular & opening choke valves & obtain a minimum of 200 psi above pre-charged within 2 minutes or less.

IV. Reservoir Capacity: 2 X times useable fluid capacity of the system.

V. Pump Coming In Time:

PUMPS	Air 60 – 1 ratio	Electric
	Kick in @ 2250 psi	Kick in @ 2700 psi
	Kick out @ 2750 psi	Kick out @ 3000 psi

Usable fluid is the volume of fluid recoverable between accumulator operating pressure & 200 psi above pre – charge.

API Defination

Every installed Ram BOP should have as a minimum a working pressure equal to the **Maximum Anticipated Surface Pressure** to be encountered.

I. Rated Working Pressure: The maximum internal pressure that equipment is designed to contain or control.

   Note: Rated Working Pressure should not be confused with test pressure.

II. Closing Ratio: The ratio of the wellhead pressure to the pressure required to close the BOP.

III. Drill Pipe Safety Valve: An essentially full – opening valve located on the drill floor with threads to match the drill pipe connection in use. This valve is used to close off or secure the drill pipe to prevent flow.

IV. Usable Fluid Volume: The volume of fluid recoverable from an accumulator between accumulator operating pressure and 200 psi above the pre-charge pressure.

V. Accumulator Pre-charge: The precharge pressure on each accumulator bottle should be measured prior to each BOP stack installation on each well and adjusted if necessary.

   The minimum precharge pressure for a 3000 psi working pressure accumulator should be 1000 psi. The minimum precharge pressure for a 5000 psi working pressure should be 1500 psi. Only nitrogen gas should be used for accumulator precharge. The precharge pressure should be checked and adjusted to within 100 psi of the selected precharge pressure at the start o drilling each well.

   For subsea installation the precharge pressure shall compensate for the water depth the BOP's will be operating in. The subsea accumulator bottle calculations should compensate hydrostatic pressure gradient at a rate of 0.445 psi / ft of water depth.

VI. Accumulator Response Time: Response time between activation and complete operation of function is based on BOP or valve closure and seal off. For surface installations, the BOP control system should be capable of closing each RAM BOP in 30 seconds or less. Closing time should not exceed 30 seconds for annular BOP's (18 ¾) and 45 seconds for annular preventers 18 ¾ and larger.

For subsea installations, the BOP control system should be capable of closing each RAM BOP in 45 seconds or less, closing time should not exceed 60 seconds for annular BOPs. Operating response time for choke and kill valve (either open or close) should not exceed the minimum observed RAM ROP close response time. Time to unlatch the lower marine riser package should not exceed 45 seconds.

7.2 Types of Tests

Test programmes incorporate **visual inspections, functional operations, pressure tests, maintenance practices** and **drills**.

7.2.1 Inspection Test

The inspection test is aimed to examine the flaws that may influence equipment performance. These tests may include but not limited to visual, dimensional, audible, hardness, functional and pressure tests.

7.2.2 Pressure Tests:

Periodic application of pressure to a piece of equipment or system to verify the pressure containment capability for the equipment or system. Wellbore test is another descriptive term frequently used synonymously for pressure testing.

All blowout preventer components that may be exposed to well pressure should be tested first to a low pressure of 200 to 300 psi and then to a high pressure.

- When performing the low pressure test, do not apply a higher pressure and bleed down to the low test pressure. The higher pressure could initiate a seal that may seal after pressure is reduced therefore misrepresenting a low pressure condition.
- A stable low pressure test should be maintained for at least 5 minutes.

The initial high pressure test on components that could be exposed to well pressure (BOP stack, choke manifolds and choke and kill lines) should be to the rated working pressure of the RAM BOP's or to the rated working pressure of the wellhead that the stack is installed on, whichever is lower. Initial pressure tests are defined as those tests that should be performed on location before the well is spudded or before the equipment is put into operational device service.

- Diverter systems are typically tested to a low pressure only *ref to API RP 64.*

- Annular BOP's with a joint of drill pipe installed may be tested to the test pressure applied to the RAM BOP's or to a minimum of 70% of the annular preventer working pressure, whichever is less. Subsequent pressure tests are tests that should be performed at identified periods during drilling and completion activity on a well.

- The lower Kelly valves, Kelly, Kelly cock, drill pipe safety valves, inside BOP, and top drive safety valves, should be tested with water pressure applied **from below** to a low pressure of 200 psi – 300 psi then to the rated working pressure.

- There may be instances when the available BOP stack and or / the wellhead have higher pressures than are required for the specific wellbore conditions due to equipment availability. Special conditions such as these should be covered in the site-specific well control pressure test program.

Subsequently, high pressure tests on the well control components should be to a pressure greater than the maximum anticipated surface pressure, but not to exceed the working pressure of the RAM BOP's.

- A stable high pressure test should be maintained for at least 5 minutes. With larger size annular BOP's some small movement typically continues within the large rubber mass for prolonged periods after pressure is applied. This packer creep movement should be considered when monitoring the pressure test of the annular.

7.2.2 Function Tests:

Function test of a piece of equipment or a system to verify its intended operation. Function testing typically does not include pressure testing. Actuation test, operating test and readiness are other terms commonly used synonymously for function test.

All operational components of the BOP equipment systems should be functioned at least once a week to verify the component's intended operations.

- Function tests should be alternated from the Driller's panel and from mini - remote panels, if on location
- Actuating time should be recorded as a data base for evaluating trends.

7.2.3 Pressure Tests:

Pressure Gauges and chart recorders should be used and all testing results recorded pressure measurements should be made at not less than 25% or more than 75% of the pressure span of the gauge.

Surface BOP Stack Equipment:

Unless restricted by height, the entire stack should be pressure tested as a unit. Annular BOP's should be tested with the smaller OD pipe to be used.

Fixed bore pipe rams should be tested only on the pipe OD size that matches the installed ram blocked.

Variable Bore Rams should be initially pressure tested on the largest and smallest OD pipe that may be used during the well operations. Prior to testing each RAM BOP, the secondary rod seals (emergency pack off assemblies) should be checked to ensure the seals have not been energized. Should the ram shaft seal leak during the test, the seal shall be repaired rather than energizing the secondary packing.

RAM BOP's equipped with ram locks should be pressure tested with ram locks in the closed position and closing pressure bled to zero. Manual locks either screw clockwise or counterclockwise, to hold the rams closed. Hand wheels should be in place and the thread on the ram locking shaft should be in a condition that allows the locks to be easily operated.

7.2.4 Hydraulic Operator Test

The application of a pressure test to any hydraulic operated component of hydraulic actuated equipment. Hydraulic operator tests are typically specified by the manufacturer for such items as: BOP operator cylinder and bonnet assemblies, hydraulic valve actuators, hydraulic connectors etc. Operating chamber test is frequently used synonymously for hydraulic operator test.

The pressure test performed on hydraulic chambers of annular BOPs should be to at least 1500 psi. Initial pressure tests on hydraulic chambers of ram BOP's and hydraulically operated valves should be to the maximum operating pressure recommended by the manufacturer.

The test should be run for both the opening and closing chambers.

Pressure should be stabilized for at least 5 minutes.

Subsequent pressure tests are typically performed on hydraulic chambers only between wells or when the equipment is reassembled.

The initial pressure test on the closing unit valves, manifolds, gauges and BOP hydraulic control lines should be to the rated working pressure of the control unit. Subsequent pressure tests of closing unit systems are typically performed following the disconnection or repair of any operating pressure containment seal in the closing unit system, but limited to the affected components.

Section D – Recommended Pressure Test Practices, Floating Rigs with Subsea BOP stacks.

Subsea: Recommended Pressure Test Practices, Floating Rigs with Subsea BOP Stacks.

Initial Test: *(diverter system prior to spud, et al, prior to running stack).*

	Component to be Tested	Recommended Pressure Test – Low Pressure, (psi)	Recommended Pressure Test –High Pressure, psi
1.	Diverter Element	Optional	*Optional*
2.	Annular Preventer (s) Opening Chamber	200 - 300 psi N/A	Minimum of 70% of annular BOP working Pressure Minimum of 1500 psi.
3.	Ram Preventers - Fixed Pipe - Variable Bore - Blind / Blind Shear - Operating Chamber	 200 -300 psi 200 -300 psi 200 -300 psi N/A	 Working Pressure of RAM BOP Working Pressure of RAM BOP Working Pressure of RAM BOP Maximum operating pressure recommended by RAM BOP manufacturer
4.	Diverter Flow Lines	Flow test	N/A
5.	Choke Lines & Valves	200 – 300 psi	Working pressure of RAM BOPs
6.	Kill Lines & Valves	200 – 300 psi	Working pressure of RAM BOPs
7.	Choke Manifold - Upstream of Last High Pressure Valve - Downstream of Last High Pressure Valve	 200 - 300 psi 200 – 300 psi	 Working Pressure of RAM BOP Optional
8.	BOP Control System - Manifold and BOP Lines - Accumulator Pressure - Close Time - Pump Capability - Control Stations	 N/A Verify Precharge Function Test Function Test Function Test	 Minimum of 3000 psi. N/A N/A N/A N/A
9.	Safety Valves - Kelly, Kelly Valves and Float Safety Valves	 200 – 300 psi	 Working Pressure of components
10.	Auxiliary Equipment - Mud / Gas Separator - Riser Slip Joint - Trip Tank, Flo – Show etc.	200 – 300 psi Flow Test Flow Test Flow Test	Optional N/A N/A N/A

**The low pressure test should be stable for a least 5 minutes.*
**The high pressure should be stable for at least 5 minutes. Flow type tests should be of sufficient duration to observe for significant leaks.*
**The rig available well control equipment may have a higher rated working pressure than site required. The site-specific test requirement should be conducted for this situation.*

Subsea: Recommended Pressure Test Practices, Floating Rigs with Subsea BOP Stacks.

Subsequent Test : [(a) BOP stack initially installed on wellhead and (b) not to exceed 21 days]

	Recommended Pressure Test – Low Pressure (psi)	Recommended Pressure Test – Low Pressure, (psi)	Components to be Tested
1	Diverter Element	Optional	*Optional*
2	Annular Preventer Opening Chamber	200 - 300 psi N/A	Minimum of 70% of annular BOP working Pressure N/A
3	Ram Preventers - Fixed Pipe - Variable Bore - Blind / Blind Shear - Casing (prior to running csg) - Operating Chamber	 200 -300 psi 200 -300 psi 200 -300 psi Optional	 Greater than the Maximum Anticipated Surface Shut – in Pressure Greater than the Maximum Anticipated Surface Shut – in Pressure Greater than the Maximum Anticipated Surface Shut – in Pressure Optional N/A
4	BOP –to- WHD Connector and Casing Seat	Flow Test	N/A
5	Diverter Flow Lines	Flow test	N/A
6	Choke Lines & Valves	200 – 300 psi	Greater than the Maximum Anticipated Surface Shut – in Pressure
7	Kill Lines & Valves	200 – 300 psi	Greater than the Maximum Anticipated Surface Shut – in Pressure
8	Choke Manifold - Upstream of Last High Pressure Valve - Downstream of Last High Pressure Valve	 200 - 300 psi 200 – 300 psi	 Greater than the Maximum Anticipated Surface Shut – in Pressure Optional
9	BOP Control System - Manifold and BOP Lines - Accumulator Pressure - Close Time - Pump Capability - Control Stations	 N/A N/A Function Test Function Test Function Test	 Optional N/A N/A N/A N/A
11.	Safety Valves - Kelly, Kelly Valves and Floor Safety Valves	 200 – 300 psi	 Greater than the Maximum Anticipated Surface Shut – in Pressure

12.	Auxiliary Equipment - Mud / Gas Separator - Riser Slip Joint - Trip Tank, Flo – Show etc.	 Flow Test Flow Test Flow Test	 N/A N/A N/A

**The low pressure test should be stable for least 5 minutes.*
**The high pressure should be stable for at least 5 minutes. Flow type tests should be of sufficient duration to observe for significant leaks.*

Note: This section deals with the surface BOP stack equipment including the wellbore pressure containing equipment above the wellhead, including the RAM BOPs, spool(s), annular(s), choke and kill valves, and choke line to the choke manifold. Equipment above the uppermost BOP is not included.

Section E – Job Safety Analysis for BOP Maintenance and Inspection.

BOP MAINTENANCE & INSPECTION JOB SAFETY ANALYSIS

JSA No:	Department: Drilling Engineering	Date Prepared: **Engr. Oseghale Lucas Okohue** Date Re Issued:	Prepared by: Re Issued: *(Print & Sign)*	Approved: Re Issued: *(Print & Sign)*

Note. C = Consequences P = Probability R = Risk

Determine risk for each hazard (with no controls in place) using risk matrix at end of this form as a guide

No	Basic Job Steps	Existing and Potential Hazards	C	P	R	Ways To Eliminate Or Control Hazards	Resid Risk H/M/L
1	Working in sub structure	• Slip hazards. • Tripping line of sight and audible gas alarms.	3	C	M	• Ensure CCR are aware of ongoing work being undertaken • Ensure permitry is in place. • Keep work site clean / tidy and free from slip and trip hazards.	L
2	Working on BOP	• Risk of tools / equipment falling.	3	C	M	• All tools used at height must be secured by a lanyard to prevent falling. • Personnel to be aware of operations taking place.	L
		• Risk of injury from falling due to slippery surface or unstable step ladder positioning.	3	C	M	• Keep work area clean / dry and free from hydraulic oil / mud spills. • When working at height a safety harness must be worn and a lanyard attached to a suitable anchor point. • If working from stepladders, ensure designated person is appointed to steady ladder.	L

						• Visually check for integrity / condition of stepladder. • Ensure stepladder is stable and supported if required.	
		• Conflict of operations taking place in same area.	3	D	L	• Liaise with other personnel working in same area. Ensure other work parties are aware of current operations.	L
		• Risk to personnel due to pressure on koomey hoses.	2	C	M	• All work group to be aware of pressure in the hoses throughout the task. • If possible bleed off pressure. • Covers to be place over koomey hoses positioned on floor. • Any spillages must be cleaned up immediately to prevent hydraulic oil entering drain system.	L
3	Working with air tools.	• Risk of personnel tripping on hoses.	3	D	L	• Secure all hoses away from walkways. • Maintain good housekeeping standards.	L
		• Risk of injury due to unexpected release of pressure.	3	C	M	• Visually check air tools and hoses for integrity / condition before & during task. • Ensure all air hose connections have R clips and whipcheck fitted. • Air lines to be depressurized during breaks.	L
		• Risk of eye injury from ejected debris.	3	D	L	• Eye goggle or full-face visor to be worn at all times when using air-operated tools.	L

						• Ensure goggles are correctly fitted to the face with no gaps that could allow particles through. If this is not possible obtain alternative style of goggle.	
		• Risk of injury due to incorrect application.	3	C	M	• Correct tools to be used and best work practices followed. • Ensure work group are aware of potential pinch points when undertaking task. • Correct PPE to be worn.	L
		• Risk of injury due to vibration (hand and arm vibration).	3	B	M	• Rotate personnel on task. • Do not exceed exposure times. • Record vibration level and trigger times for each tool used by each individual during shift.	L
4	Use of lifting equipment.	• Risk of injury due to lifting gear failure.	3	C	M	• Personnel must never stand under a suspended load. Always have an unobstructed escape route should the lifting equipment fail and avoidance is required. • All lifting equipment to be inspected prior to use for suitability, integrity & certification. • Check equipment of equipment throughout task.	L

						• Only competent personnel to use / rig-up equipment. • Do not exceed SWL, if in doubt stop task reassess / clarification.	
5	Manual Handling of Equipment.	• Risk of injury due to incorrect manual handling and / or not using enough personnel.	3	C	M	• Good manual handling techniques to be used at all times i.e. kinetic lifting. • Ensure sufficient personnel are available. • Use mechanical aids whenever possible.	L
6	Removing Rams	• Well begins to flow during operation	2	D	M	• Continuous monitoring by Driller • Pressure tested Deep set plug and Kill weight fluid in hole. • Flow check on well prior to start of operation. • Make up TDS to drill pipe stand prior to start. • 9 5/8 annulus to be continually observed	L
7	Rams removed	• Well begins to flow during operation	2	D	M	• Close Ram bonnets and secure. • Lower hanger assembly and land out on wellhead and secure tie down bolts • 9 5/8 annulus to be ready to hook up to production train.	L
		• Risk of injury if Koomey valves operated	2	D	M	• Pressure to be bled off from Koomey unit	L
		• Risk of injury if Pipe moved	2	D	M	• Brake to be chained down & locked, sign posted	L

- **With controls in place, are residual risks deemed to be Low and ALARP? (State Yes or No)** **Yes**

NB - *If any Residual Risk is determined as other than Low - higher level approval is required.*

Permit Type(s) Required?	Cold work	**Isolation Type(s) Required?**	No	**Temporary Defeat(s) Required?**	No	**COSHH Assessment Required?**	No	**Manual Handling Assessment Required?**	Yes	**PUWER Assessment required**	No
Lessons learned carrying out activity on previous occasions											

Determine the Risk

Consequences

Category	Health or Safety	Public Disruption	Environmental Impact	Example Scenarios with Potential SHE impact
1	Fatalities or serious impact on public	Large community	Major or extended duration or full scale response	• Major fire or explosion • Significant hydrocarbon release • Toxic release
2	Serious injury or limited impact on public	Small community	Serious or significant resource commitment	• Fire or small hydrocarbon release • Spill to water • Large spill to land
3	Medical treatment injury	Minor	Moderate or limited response of short duration	• Non Toxic release • Minor fire • Environmental exceedance
4	Minor impact on personnel	Minimal to none	Minimal to none	• Minor leak with negligible impact

Probability

A	Very Likely
B	Somewhat Likely
C	Unlikely
D	Very Unlikely
E	Practically impossible

Risk Matrix (Probability x Consequence = Risk)

Probability

Consequence

	A	B	C	D	E
1					
2					
3					
4					

Risk

High	
Medium	
Lower	