3. EQUIPMENT DESCRIPTIONS, OPERATING CHARACTERISTICS, AND REQUIREMENTS

3-1 GENERAL

This section discusses the components of Classes II through IV BOPE systems as outlined in Section 2. The components are grouped into the following classifications: preventers, the actuating system, the choke and kill system, auxiliary equipment, and hole-fluid monitoring equipment.

Upon receipt of a proposal to conduct well operations, division engineers use the guidelines contained in this manual to develop BOPE requirements for the well, which will be conveyed to the operator in a permit to conduct well operations. The requirements stated on the permit constitute the minimum standards for the BOPE system when it is inspected in the field. Any proposed deviation from these standards must be approved, in writing, by the division prior to inspection. **If any component fails to meet these standards, the entire equipment array must be considered inadequate and no operations will be permitted until the inadequacy has been corrected to the satisfaction of the division.**

One of the most important components of the BOPE array is the metal ring-joint gasket, or API ring. These gaskets provide the pressure seal in a flange connection and they are used at several points in BOPE systems. Many of the system failures seen in the field by division inspectors can be traced directly to poor practices by rig crews in the selection and use of these gaskets. If a gasket is to function properly, it must be in new, or near-new, condition and the ring groove into which the gasket is to be inserted must be undamaged, clean, and dry. Attempting to reuse a ring-joint gasket several times, or to seat a ring-joint gasket in a damaged or contaminated ring groove, increases greatly the chance of pressure failure. In fact, API Specification 6A recommends against reusing BX 150 through BX 160 rings. Another common mistake is lubricating the ring groove before inserting the gasket. Protecting the ring groove with lubrication is a commendable practice while the flange is in storage, but any protective coating must be removed completely before attempting to seat a ring-joint gasket in the groove.

3-2 PREVENTERS

Preventers are devices designed to prevent the uncontrolled flow of well bore fluids through the casing, by either containing the flow completely or by diverting it to a more desirable location through a system of piping and valves. Preventers are classified as annular or ram-type.

a. **Annular, or "bag" preventers** are those designed to completely fill any annular space in the well bore by hydraulically extruding or inflating a resilient packing element inward from the housing of the preventer, sealing around virtually any object that will fit in the throughbore of the preventer. These preventers will also seal off an open hole, but that is not their primary function, and doing so might shorten the life of the packing element. The following must be considered when using annular preventers:

Annular preventer. This Hydril annular preventer contains an elastomer packing element which, when compressed by hydraulic pressure applied beneath a contractor piston, forces the packing unit inward into a sealing engagement with any part of the drill string. This enables the preventer to close off any annular space, regardless of the size or cross-sectional shape of the annulus, up to and including full closure on open hole. Closing pressure should be regulated carefully at the control manifold to prevent needless extrusion of the packing element. *Photo courtesy of Hydril Company.*

1. In Class I or Class II installations, an annular preventer may be the only blowout preventer on the wellhead. Such a well must not be left unattended with pipe in the hole and the annular preventer closed on the pipe. Instead, the pipe must be removed, a bailing gate or some other type of full-closing valve must be installed above the annular preventer, and this valve must be closed. This requirement is necessary because a loss of pressure in the closing chamber of an annular preventer (due to any type of failure in the hydraulic actuating system) will permit the elastic memory of the packing element to reopen the preventer.

2. Supervisory personnel should become familiar with the basic design of the annular preventer that is in use on their particular well because there is an important difference in the way different designs respond to increasing well pressure. Most annular preventers are designed to close by having an operating piston driven upward by hydraulic pressure applied beneath the piston. In most cases, the piston has some lower surfaces exposed to the fluids in the well bore. In this design, an increase in well pressure under a closed annular preventer will increase the closing force of the preventer against the pipe, etc.

   Some designs, particularly those intended for use in deep water subsea stacks, have isolated the closing piston from the well bore or balanced the riser pressures so the closing effect of a wellbore pressure increase is reduced or eliminated, and the increasing well-bore pressure tends to open the preventer. In the Regan-type annular preventer, an inner sleeve is inflated into the well bore by injecting hydraulic fluid behind it, and any increase in hole pressure will work to open the preventer. In this situation, the wellbore pressure must be monitored continually so the closing pressure may be adjusted accordingly.

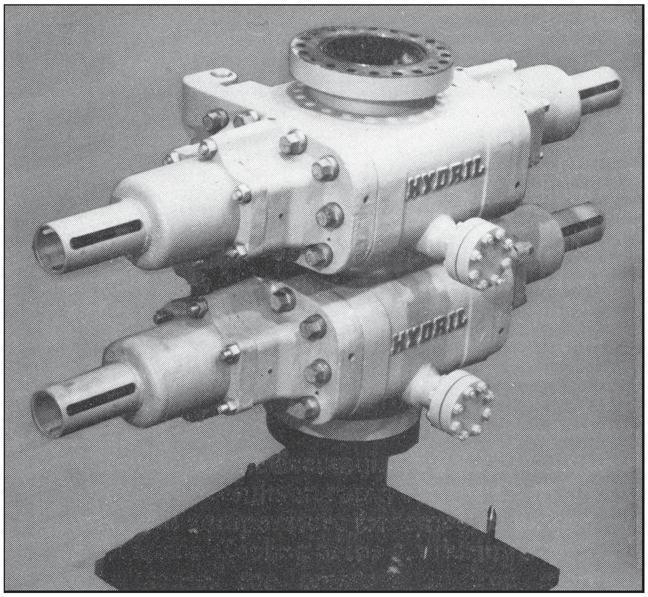
3. Also, all members of the rig crew should be trained in the proper use of the pressure-regulating valve on the accumulator unit control so the closing pressure does not exceed that actually required to keep the packing element pressed against the pipe, considering the pipe size and the pressure in the annulus. Tables of these pressures are available from the manufacturers and should be made available at the well site. Using the lowest practicable closing pressure will prolong the life of the packing element and permit tool joints to be stripped through the preventer with minimum damage to the packing element. In fact, when attempting to strip pipe or rotate while the annular preventer is closed, the flow line should be monitored to permit slight leakage of wellbore fluid between the pipe wall and the closing surface of the preventer. The leakage will lubricate the surface of the pipe, reducing the rate of damage to the packing element of the preventer.

4. Crews should also be trained to protect the upper API ring groove on an annular preventer. Normally, the upper connection is to the pitcher nipple and pressure integrity at that connection is not a consideration; however, supervisors should be aware that it may become necessary to attach additional preventers or a snubbing assembly above the annular preventer during a well-control emergency. In such cases, the condition of the API ring groove becomes very important. Particular attention must be paid to protecting the upper surface of the annular preventer during workover operations when Class II BOPE is employed and the annular preventer may be used with nothing installed above it. Unless the top surface of the preventer is provided with a protective plate, the bolt holes will fill with debris and any off-center tool joints striking the preventer will damage that surface, eventually compromising the usefulness of the API ring groove.

b. **Ram preventers** are gate valves utilizing two opposing horizontal sliding gates, or ram assemblies, that are forced toward each other by pneumatic or hydraulic pressure or by mechanical screws. Each ram assembly has an elastomer ram rubber that seals the upper surface of the ram assembly against the seal seat in the preventer housing at the same time as the closing surface seals against the pipe and/or the opposite ram assembly.

   A unique type of ram preventer that does not quite fit the description given above is the slab gate used while drilling some geothermal wells. This type of preventer does not use two opposing ram assemblies. Instead, a single ram gate is employed and driven completely across the well bore to accomplish full closure. When used, the slab gate is mounted directly above the casinghead, forming the base for the rest of the BOP stack.

   Ram preventers are designed so the lower and rear surfaces of the ram assemblies are always exposed to the well bore. Any additional wellbore pressure against the lower surface of the assembly increases



Double ram-type preventer. Two ram-type preventers built into one casting conserve vertical space, minimize the number of connections, and simplify installation. Usually, choke and kill connections are made to a drilling spool below the preventers. Such connections may be made to the side outlets, visible on the preventer body, but this is not common practice. A flange failure at one of the side outlets might necessitate changing the entire preventer. *Photo courtesy of Hydril Company.*

the pressure of the ram against the seal seat in the preventer body, and the pressure against the back of the ram assembly increases the effectiveness of the seal against the pipe and/or the opposite ram.

Some rams will hold pressure effectively only when the proper side of the assembly is facing up, making it important that precautions be taken to ensure correct installation. The body of the preventer is designed so the rams may be replaced or exchanged easily.

The following points must be considered when using ram preventers:

Every ram-type preventer, with the exception of a slab gate, must have some type of positive-locking device. Some of the newer designs, particularly those built for subsea service, have an automatic locking feature that will prevent accidental opening of the rams in the event of failure of the actuating system; however, most of the hydraulically-operated ram-type preventers currently available for onshore use must be locked mechanically in the closed position with hand wheels or a socket device. These manual-locking devices may also be used to close a ram preventer in the event of an actuating system failure, provided the four-way operating valve to that preventer has first been placed in the CLOSE position or the hydraulic lines have been loosened to prevent the trapping of incompressible hydraulic fluid in the opening chamber. These preventers may only be opened hydraulically. Any manual-locking device must be tested by full operation, at an interval not to exceed one month, while the preventer is in use.

The ram body must be installed with the proper side up. The top of the ram cavity contains a smooth seal seat around the margin of the throughbore, while the bottom of the cavity will usually be fitted with a series of raised ramps upon which the ram assemblies ride. This provides the floating ram feature that is common to all ram preventers, regardless of manufacturer.

If the ram body is installed with the raised ramps uppermost, the rams will not provide a reliable seal with pressure in the wellbore.

Three categories of rams are currently in use, each designed for a specific job, as opposed to the general-use nature of the annular preventer.

1. ***Blind (Complete Shutoff) rams*** are used when there are no tools or pipe in the hole. Although there are valid arguments against doing so, it is often considered good practice to install the blind rams above at least one set of pipe rams in the stack so the blind rams may be isolated from any hole pressures and exchanged for pipe rams if a kick occurs. Because over half of all kicks occur with pipe in the hole, blind rams are not used in most kick situations. The overall usefulness of the BOP stack is reduced if the blind ram assemblies cannot be isolated and exchanged for pipe ram assemblies while there is pressure in the well bore.

   If the blind rams have been closed to permit the alteration or repair of any equipment higher in the BOP stack, the rams must be locked closed to prevent accidental opening before the work has been completed.

2. ***Pipe rams*** have a semicircular notch in the closing surface of the ram assembly that fits around the body of the pipe when the rams are closed. Guide tapers center the pipe in this opening as the leading edges of the closing surfaces come together.

Many pipe-ram rubbers are designed to adjust automatically for wear of the sealing surfaces. Usually, this is accomplished by inlaying horizontal metal extrusion plates into the upper and lower surfaces of the ram rubbers, with reserve rubber behind the plates. As the normal pipe sealing surface of the ram rubber wears away, the inner edge of the extrusion plate comes into contact with the body of the pipe and the extrusion plate on the opposite ram rubber. The closing motion of the rams will press the extrusion plates into the reserve rubber area and drive the rubber into the well bore, rejuvenating the sealing surface of the ram. This self-feeding feature in the pipe ram requires that the pipe sealing surface of the ram rubber have pipe to press against, and is the reason that *pipe rams should not be closed on open hole*. They may be moved partially toward the CLOSE position to check the installation and function of the control lines, but they should not be allowed to close completely.

Care must be exercised to ensure that external upsets in the pipe string are clear of the rams when they are closed, as a reliable seal can only be obtained on the OD of the pipe body. Unless the BOP stack contains the newer variable-type pipe-ram assemblies, which will close on a range of pipe sizes, a different set of rams must be installed in the stack for each pipe size used (exclusive of the drill collars and any smaller-diameter stinger pipe less than about 600 feet long).

3. ***Blind-shear rams*** are bladed rams capable of cutting through most pipe in the well bore and effecting full closure in an emergency. At least one set must be installed in all ocean floor BOPE stacks. Most ram manufacturers provide a special, large-diameter operating cylinder, sometimes referred to as a shear booster, for use with blind-shear rams to provide more operating pressure on the blades. The added force increases the probability that the blades will be able to cut through heavy-wall drill pipe and drill collars.

   Usually, shear rams are installed in the uppermost ram preventer. A set of pipe rams, designated as hang-off rams and installed below the shear rams, may be closed and the pipe lowered until an upset or collar is resting on the top of the rams. Then, the blind-shear rams may be closed, cutting the pipe. Hopefully, the severed pipe string will be supported by the hang-off rams below the upset. Shear rams are designed so an opening will normally remain in the cut-off stub. This allows circulation to be reestablished through the pipe still in the hole, using the choke and kill systems.

c. If a **preventer has been closed** for any reason, before the preventer is reopened, the hole space below that preventer must be vented through the choke line or a relief valve to bleed off any trapped pressure.

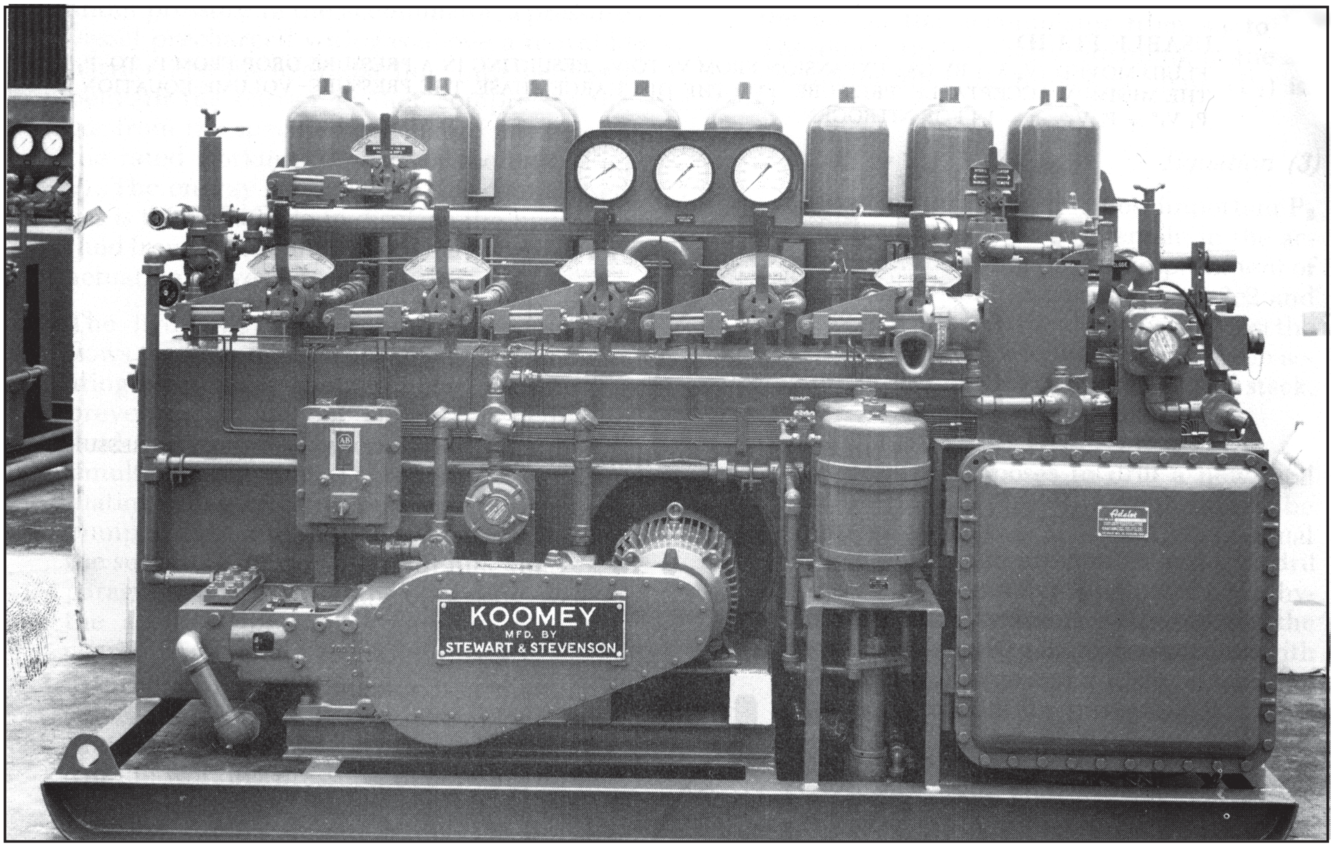
3-3 THE ACTUATING SYSTEM

The actuating system provides the means of operating the preventers and, in many cases, other equipment in the BOPE array from a remote location. The actuating system for a hydraulically-operated preventer stack consists of an accumulator unit, an emergency backup system, a control manifold, one or more remote stations, hydraulic control lines, and hydraulic fluid.

Since the closing of a preventer may be an emergency action, it must be accomplished quickly and with sufficient force to overcome the pressure of any fluid in the well bore. Therefore, the operating system must be capable of providing adequate quantities of closing fluid at reasonably high pressures. The most effective actuating system currently available uses the hydropneumatic -- or liquid-gas -- accumulator as its source of energy.

Other, less-effective systems include the manual/mechanical method in which the ram preventers are screwed shut using hand wheels, and the direct-acting hydraulic or pneumatic systems in which annular or ram-type preventers may be forced shut by pumping liquid or applying compressed gas directly against the closing piston or the back of the packing unit, without the use of a pressure accumulator. The following discussion is limited to the components of the hydropneumatic accumulator system, the most common system in use.

a. The **accumulator unit** (closing unit) is a system of pumps, valves, and pressure vessels designed to provide an instantly available source of pressurized hydraulic fluid for operating the preventers and other equipment. The fluid is provided from a reservoir and stored under pressure in one or more accumulators. The accumulator is a pressure vessel precharged with nitrogen, usually above or within a movable barrier. Forcing hydraulic fluid into the vessel on the opposite side of the barrier further compresses the gas until the gas pressure rises from the specified precharge



Typical Koomey accumulator unit. The upright bottles at the back of the unit are the hydropneumatic accumulators, each having a total capacity of approximately ten gallons. The three gauges indicate, from left to right, the reduced pressure to the manifold, the pressure in the accumulators, and the regulated pressure to the annular preventer. Pressure to the manifold and to the annular preventer is regulated by the upright valves with the winged ball handles at each end of the unit. The fluid reservoir is beneath the control handles and the charging pumps are in the foreground. Note that this particular unit, as shown, has no emergency backup system. Such a backup system, e.g. high-pressure nitrogen cylinders, would not employ the accumulator(s) as a source of operating pressure. *Photo courtesy of Stewart & Stevenson Oiltools, Inc.*

pressure to the rated working pressure of the unit (Fig. 9). Then, the energy of this compressed gas is available to displace the hydraulic fluid from the accumulator when a preventer-actuating valve is operated.

The operating cycle of the accumulator unit is composed of a discharge phase and a recharge phase. The hydraulic fluid from the accumulator flows through an actuating valve (four-way valve) in the control manifold to an operating chamber in the preventer, causing the preventer to open or close. The hydraulic fluid in the opposing operating chamber is simultaneously vented through the same actuating valve into the reservoir, where it is available to be pumped back into the accumulator(s), restoring the supply of pressurized hydraulic fluid (see paragraph 3-3c).

1. Charging the accumulator is usually a matter of slow compression. It may take 45 minutes or longer to charge from the precharge pressure to the working pressure, depending on the accumulator capacity and the pump output. Except in the case of very large accumulator volumes (200 gallons or larger) the effect of temperature change during the recharge phase can be ignored; therefore, the pressure-volume relationship during recharge is:

$P_1V_1 = P_2V_2$ *Equation* (1)

P_1 = initial pressure

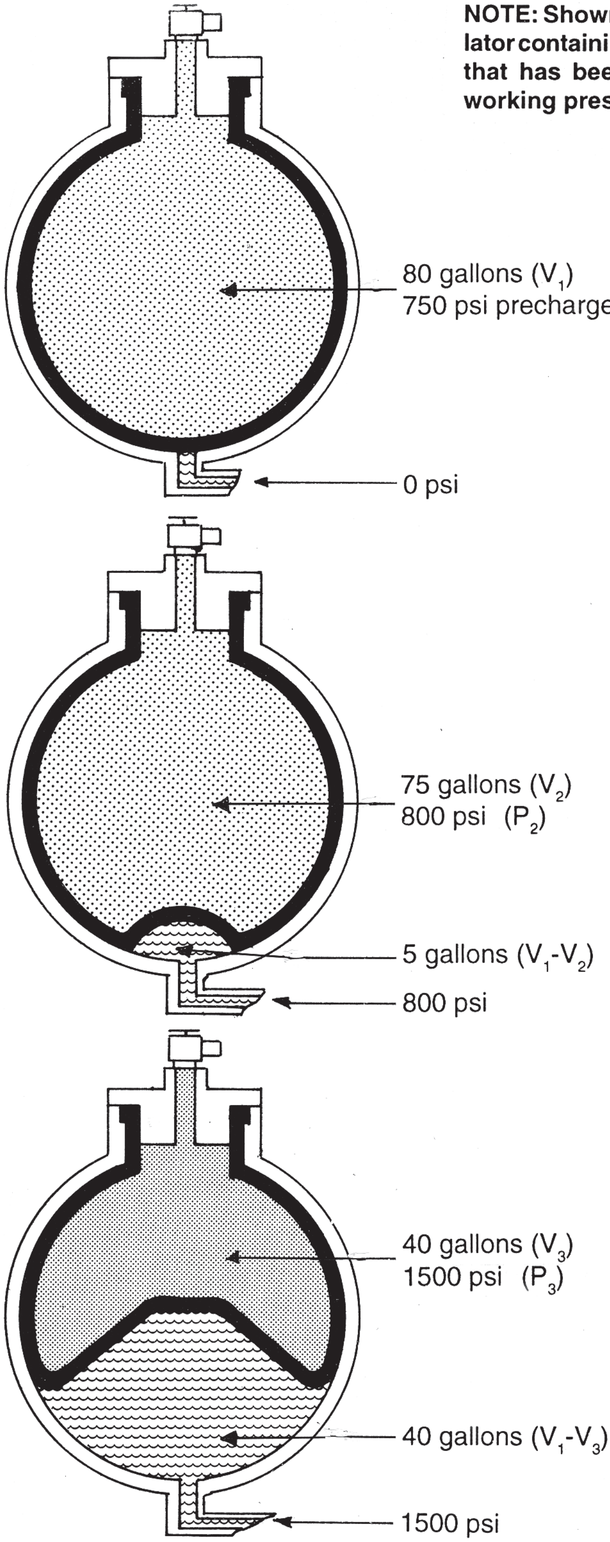
P_2 = pressure at V_2

V_1 = initial volume

V_2 = volume at P_2

For an 80-gallon accumulator system (V_1) in good repair with a 750 psi precharge (P_1) and a

NOTE: Shown is an 80-gallon spherical accumulator containing a bag-type elastomer diaphragm that has been precharged at 750 psi (I). The working pressure (full charge) is 1500 psi (III).



I

The hydraulic system is discharged (0 psi). The diaphragm completely fills the accumulator (V_1) and contains the specified precharge of 750 psi (P_1).

II

The accumulator pump has begun to force hydraulic fluid into the accumulator below the diaphragm. The gas inside the diaphragm is being compressed (V_2), with a corresponding increase in pressure (P_2).

III

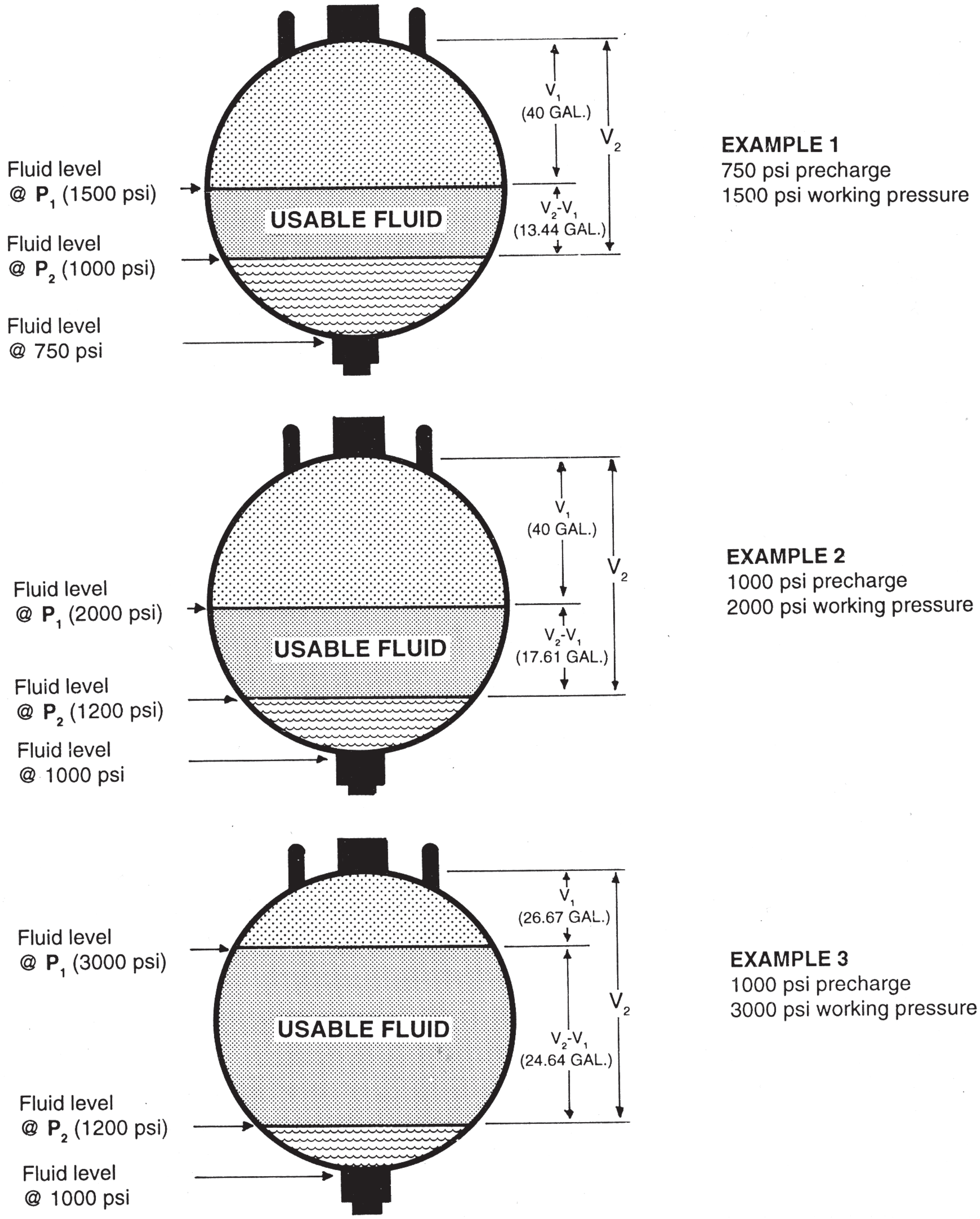
The accumulator is fully charged with hydraulic fluid to the rated working pressure. The gas above the diaphragm has been compressed to a volume of 40 gallons (V_3), and exerts a pressure of 1500 psi (P_3) on the hydraulic fluid.

$$P_1V_1 = P_2V_2 = P_3V_3$$

PRESSURE-VOLUME RELATIONSHIPS IN AN ACCUMULATOR DURING THE RECHARGE PHASE
FIGURE 9

USABLE FLUID

FLUID MOVED (V_2-V_1) BY GAS EXPANSION FROM V_1 TO V_2, RESULTING IN A PRESSURE DROP FROM P_1 TO P_2, THE MINIMUM ACCEPTABLE PRESSURE FOR THE DISCHARGE PHASE, THE PRESSURE-VOLUME EQUATION IS $P_1V_1^n=P_2V_2^n$ (n=1.4 FOR NITROGEN).



RELATIVE VOLUMES OF USABLE FLUID DURING DISCHARGE IN 80-GALLON ACCUMULATORS, SHOWING THE EFFECT OF PRECHARGE AND WORKING PRESSURE

FIGURE 10

1,500 psi working pressure (P_2), Equation (1) yields a total fluid capacity of 40 gallons (V_1-V_2). *When making any accumulator calculations*, *it should be noted that the volumes in the equations are always those of the gas, not of the hydraulic fluid.* The volume of hydraulic fluid involved in the change from one condition to another is equal to the *difference* between the initial and final gas volumes (V_1-V_2).

2. Discharging the accumulator by actuating a preventer results in rapid expansion (cooling) of the gas, and temperature becomes an important factor. Cooling the gas during expansion causes the pressure to drop more rapidly than would be calculated by Equation (1), so the pressure-volume relationship during the discharge phase is:

   $P_1V_1^n = P_2V_2^n$ *Equation* (2)

   n = 1.4 for nitrogen.

   The displacement of a hydraulic fluid volume (V_2-V_1) is accompanied by the expansion of the gas in the accumulator from V_1 to V_2. Therefore, the pressure remaining in the accumulator after the discharge phase (P_2) is:

   $P_2 = P_1(V_1/V_2)^{1.4}$ *Equation* (3)

   For testing purposes, the most important P_2 is the pressure that must remain in the accumulator following the accomplishment of the actions listed in paragraph 5-2a4. Equation (3) should only be used to test the THEORETICAL adequacy of any given accumulator unit for a proposed BOP stack. The ACTUAL adequacy of the accumulator unit depends on the condition of the unit and the preventers, and can only be confirmed by field testing using the actions required in paragraph 5-2a4.

SAMPLE PROBLEM FOR DETERMINING ADEQUACY OF THE SYSTEM

An operator proposes to drill a new well with 4-1/2" drill pipe. The wellhead is to be equipped with 10", 3,000 psi equipment, including two Shaffer LWS manual-lock ram preventers and a Hydril GK annular preventer. No hydraulic control valve is proposed for the choke line. Is an 80 gallon accumulator with a 750 psi precharge and a 1,500 psi working pressure adequate for this system?

SOLUTION:

STEP 1. Determine values for the terms in Equation (3).

a) P_1 = 1,500 psi.

b) V_1 = 40 gallons (Fig. 10, Example 1).

c) V_2 = V_1 plus the volume of working fluid required to cycle one of the ram preventers and close the annular preventer on the smallest OD pipe for which pipe rams have been installed (from Appendix A and Appendix B, Table B.2). This is the working fluid required by paragraph 5-2a4 of this manual.

   Ram preventer - (1.75 gal. to close + 1.45 gal. to open) = 3.2 gal.

   Annular preventer - gallons to close on 4-1/2" drill pipe = 5.3 gal.

   Total fluid required to perform all of the above actions= (3.2 gal. + 5.3 gal.) = 8.5 gal.

   V_2 = 40 gal. plus the fluid required to perform the actions listed above= (40 gal. + 8.5 gal.)= 48.5 gal.

STEP 2. Calculate P_2 using these values in Equation (3).

   $P_2 = P_1(V_1/V_2)^{1.4} = 1{,}500(40/48.5)^{1.4} = 1{,}145$ psi

   (See Appendix F, Fig F-1 for a graphical solution using V_2 - V_1 of 8.5 gal.)

   This pressure is above the 1,000 psi minimum acceptable pressure for this type of accumulator, so the system is **theoretically** adequate. The graphs in Appendix F assist in determining the theoretical adequacy of various accumulator systems.

   The type of accumulator unit used in this problem, as shown in Example 1 of Figure 10 (750 psi precharge, 1500 psi working pressure), indicates a usable fluid volume of 13.44 gal at 1,500 psi. Therefore, the usable fluid safety margin of the accumulator unit in this problem is equal to the total usable fluid (13.44 gal.) minus the working fluid required for the BOP stack (8.50 gal), or 4.94

gal. A margin of this size can be diminished or eliminated quickly by deficiencies such as low precharge pressure or fluid leakage in any part of the system.

Table 5A, API Recommended Practice 53, contains a listing of "size factors" for various types of accumulator units. The size factor is a number that must be multiplied by the working fluid requirement of a BOP stack to arrive at the total accumulator bottle volume required for an adequate accumulator unit for the stack. Although this factor is a valid starting point in the selection process for an accumulator unit, it results in a number that would provide **theoretical** adequacy only. A field test as outlined in paragraph 5-2a4 will confirm the actual adequacy of the accumulator unit in use.

3. The general requirements for any remote-controlled actuating system are:

   a) The source of actuating fluid must be located at least 50 feet from the center of the well bore. The BOPE controls must be clearly visible and readily accessible to the crew.

   b) If the actuating system includes a hydropneumatic accumulator unit, the accumulator vessel(s) must be precharged to a pressure no lower than the manufacturer's design precharge.

   c) The level of hydraulic fluid in the accumulator unit reservoir, with the accumulator(s) fully charged, must be maintained at or above a point that would permit draining the fluid from the working bank without overflowing the reservoir.

   d) The volume of usable fluid, as defined in the note to paragraphs 2-2d2 and 2-2e2, must be sufficient to perform the actions required by those paragraphs.

   e) All actuating system valves, including any pressure regulating valves, must be in good condition and must be equipped with satisfactory handles.

   f) All pressure gauges must be reasonably accurate and in good condition, and the gauge faces must be fully readable.

   g) Each hydropneumatic accumulator must be equipped with an emergency backup system as described in paragraph 3-3b that follows.

b. An **emergency backup system** must be included as an accessory to the accumulator unit to provide an additional source of energy that is independent of the accumulators, themselves. This backup system must be of a type that can be used in a potentially explosive environment where the use of recharging pump motors or engines might provide a source of ignition.

Any backup system that is capable of performing the same emergency operations as the primary system is acceptable.

There are two principle types of backup systems: the high pressure nitrogen system and the accumulator system.

1. ***High-pressure nitrogen backup***. At this time, the backup system most commonly used in California is the high pressure nitrogen system, employing a supply of bottled nitrogen as its energy source. When needed, this gas can be released into the control manifold to restore or increase the actuating pressure.

   An advantage of the nitrogen system is that it provides a ready source of compressed gas that may be used to maintain or restore the accumulator precharge pressure, provided the accessories for doing so are maintained at the well site.

   The main disadvantage of the nitrogen backup system is that its use requires special training and discipline on the part of the crew, because the actuation sequence is very different from that employed when the accumulator unit is operating normally. To operate the nitrogen backup system, the following sequence of actions is employed:

   a) Check to see that the isolation valve is closed in the backup system line, from the nitrogen bottles to the operating manifold of the actuating unit.

   b) Decide which preventer is to be closed.

   c) Move the 4-way actuating valve for that preventer to the CLOSE position.

d) Open the isolation valve between the nitrogen bank and the control manifold.

e) SLOWLY open the valve on ONE nitrogen bottle.

f) If there is not enough usable fluid equivalent in one bottle, the valve on that bottle should be closed and the valve on the next bottle opened slowly. **Note**: No more than one nitrogen bottle should be open in the system at any time; otherwise, the pressure from a full bottle will equalize into any depleted bottle(s) without doing useful work at the BOPE stack.

g) If the preventer must be reopened with nitrogen, any open bottles should first be closed off and then the pressure should be bled from the manifold through the bypass valve into the reservoir before attempting to open the preventer.

The pressure in the nitrogen cylinders must be checked periodically to ensure there is no leakage that would affect their usefulness in an emergency (see paragraph 5-2b1).

The most common nitrogen cylinder in the field has a length of 51 inches (L on Fig. 11) and is delivered with a charge of between 2,015 psi and 2,490 psi, depending on the type of cylinder. The larger, less common cylinder measures 55 inches and is delivered with a charge of 2,400 psi or 2,640 psi, depending on the type of cylinder. A graph (Fig. 11) may be used to determine the usable volume of working-fluid equivalent remaining in each of these cylinder types at pressures above the minimum acceptable pressure for the accumulator unit in use.

The general requirements for any high-pressure nitrogen backup system are:

(a) The system must be provided with an independent, accurate pressure gauge.

(b) The accumulator unit must be provided with an isolation valve between the nitrogen bottles and the operating manifold to isolate the backup system from the accumulator(s), and a check valve positioned between the isolation valve and the nitrogen bottles to prevent pressure equalization when the system is used. The system may also be equipped with a bleed valve upstream of the check and isolation valves so the pressure may be bled from the nitrogen lines to check for an accurate reading of “zero” on the backup system pressure gauge, just discussed.

(c) Each nitrogen cylinder must contain a pressure charge not less than 500 psi above the rated precharge of the accumulator. However, the nitrogen cylinders, collectively, must contain enough working-fluid equivalent to fulfill the requirements of paragraphs 5-2a4. If any nitrogen cylinder has a charge less than the required pressure, the cylinder must be disconnected from the backup system manifold and its point of attachment to the manifold must be plugged until a replacement cylinder is attached. This requirement will prevent the loss of backup system pressure to the atmosphere or a depleted cylinder during emergency operation.

(d) Each cylinder must have a shutoff valve that is hand-operable by a person standing on the surface upon which the backup system rests.

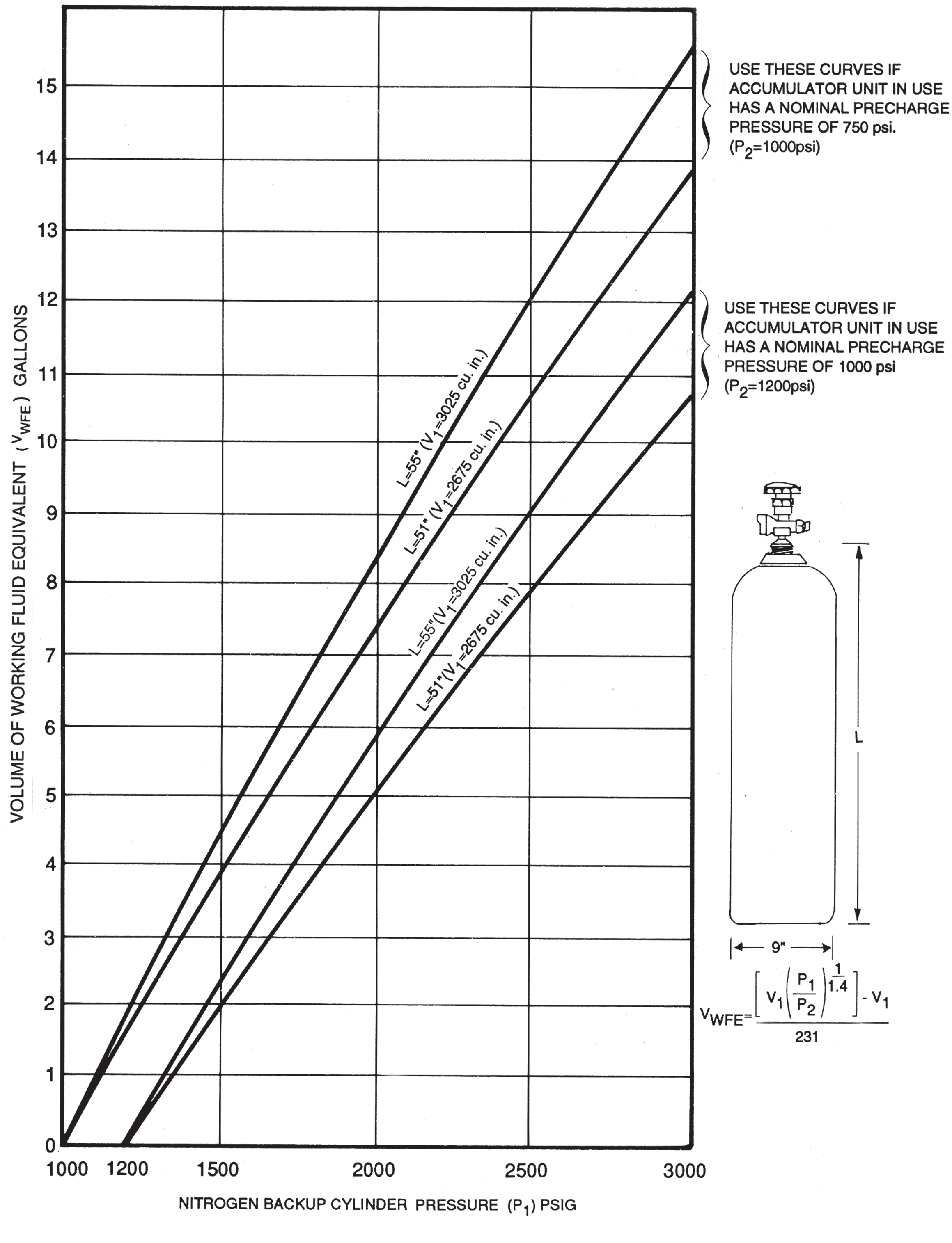
2. ***Accumulator backup***. In addition to the working bank(s), this type of backup system employs a bank (or banks) of accumulator bottles that can be called into service if the charge in the working bank fails for any reason, or if the working-fluid volume is inadequate.

The principal advantage of this type of system is that it functions in the same manner as the regular accumulator system. Before using the system, the crew must disconnect any electric- or gasoline-powered recharging pumps (to avoid ignition of any gas from the well) and isolate the backup bank from the working bank (to prevent equalization of the backup fluid pressure into the working accumulator bank).

The disadvantage of this type of system is that nitrogen would have to be brought in if the accumulator precharge needed adjustment.

The general requirements for any accumulator backup system are:

a) Both the backup bank(s) and the working accumulator bank(s) must be equipped with line valves where they join the rest of the accumulator unit piping. Then, the backup bank can be isolated from the system during normal use, and the working bank can be isolated before the backup bank is brought into use.



$$V_{WFE} = \frac{\left[V_1 \left(\frac{P_1}{P_2} \right)^{\frac{1}{1.4}} \right] - V_1}{231}$$

VOLUME OF WORKING FLUID EQUIVALENT VS. NITROGEN CYLINDER PRESSURE FOR INDIVIDUAL CYLINDERS IN A HIGH PRESSURE EMERGENCY BACKUP SYSTEM.

FIGURE 11

b) The backup bank(s) must contain enough usable fluid to fulfill the requirements of paragraphs 5-2a4.

c. The **control manifold** has as its principal feature an array of four-way valves, each of which regulates the flow of hydraulic fluid to one of the preventers in the BOP stack or to a remotely operated valve on the kill or choke line. If the control manifold is not integrated with the accumulator unit, two hydraulic lines will connect the manifold to the unit. One of these is the pressure line from the accumulator(s) and the other is the return line to the reservoir. Each of the four-way valves is connected to both of these lines and to the closing and opening lines of one of the preventers. If the manifold is integrated with the accumulator unit, each four-way valve will have its own return line to the reservoir .

When the four-way valve handle is moved to the CLOSE position, the accumulator pressure is opened to the preventer closing line and, simultaneously, the preventer opening line is vented through the return line to the reservoir. Fluid from the pressure line enters the closing chamber of the preventer and moves the actuating piston, which displaces the fluid from the opening chamber. This process is reversed when the handle is moved to the OPEN position, so the preventer is always pressurized in either the open or closed position by the working pressure of the accumulator.

If the handle is centered in the neutral position, halfway between the OPEN and CLOSE handle positions, all lines except the return line are blocked to the reservoir, and the valve acts as a locking device. This presents a potentially dangerous situation, because the preventer will be locked in position and the crew has no way of knowing what that position is.

For this reason, *the four-way valves must not be maintained in a neutral position during normal well operations.* However, there are a few circumstances in which neutral positioning of the valve handles is acceptable. These are:

- When the accumulator unit has been disconnected from the preventer control lines, with pressure in the accumulator lines.

  This condition should only be tolerated for brief periods during short rig moves, etc. The accumulator lines should be depressurized before the unit is hauled on any public road or placed in storage. Operators, contractors, and rental companies should be aware that a pressurized accumulator is a hazardous load and must be labeled according to DOT requirements when it is transported.

- During accumulator-unit testing or trouble shooting when it is necessary to isolate a portion of the system.

- During the final stages of circulating a gas kick out of the hole, when the well has been shut in with pipe rams and gas is passing through the choke line.

Placing the four-way valve in neutral will offer a measure of protection against gas that might bypass the ram shaft packing, enter the opening chamber of the preventer, and be vented to the accumulator unit reservoir if the four-way valve is left in the CLOSE position. Because the reservoir is vented to the atmosphere, any electric- or gasoline-engine driven recharging pumps would present a possible source of ignition to the vented gas.

A system leak is indicated *if neutral handle positioning is necessary to preserve the accumulator pressure*. It is probable that one of the four-way valves is bypassing fluid directly from the pressure line to the return line, or that the seal rings in the preventers are defective. For these types of system leaks, bypassing fluid can be seen entering the reservoir from the return line outlet. *This condition must be corrected before the system can be approved,* because the accumulator pressure will decline, resulting in intermittent starting and stopping of the accumulator pump(s).

An important component of the control manifold is the **pressure-regulating valve** on the pressure line leading to the four-way valve that actuates the annular preventer. As mentioned in paragraph 3-2a3, this valve should be used to regulate pressure in the closing line at the lowest pressure actually required to seal the packing element of the preventer against the pipe in the well bore. Once this reduced pressure is applied, as indicated by the pressure gauge on the regulated pressure chamber of the valve, it will be maintained automatically.

When pipe upsets or tools of greater diameter than the body of the pipe enter the packing element of the annular preventer, as would happen if the pipe were being stripped under pressure, the element will move outward, exerting additional downward pressure on the operating piston and causing higher pressure in the closing chamber of the preventer. When properly adjusted, the regulating valve will permit fluid to be displaced from the preventer into the accumulator reservoir so the pressure against the packing element will return to the adjusted value. The ejected fluid is replaced automatically from the pressure line after a larger-diameter tool or upset has passed through the packing element.

Use of minimum closing pressure while working pipe will permit a small leakage of hole fluid past the packing element, evidenced by minor flow through the flow line. This leakage will lubricate the walls of the pipe string and prolong the useful life of the packing element.

The general requirements for any accumulator-unit control manifold are:

1. The manifold must be integrated with or positioned in the immediate vicinity of the accumulator unit.

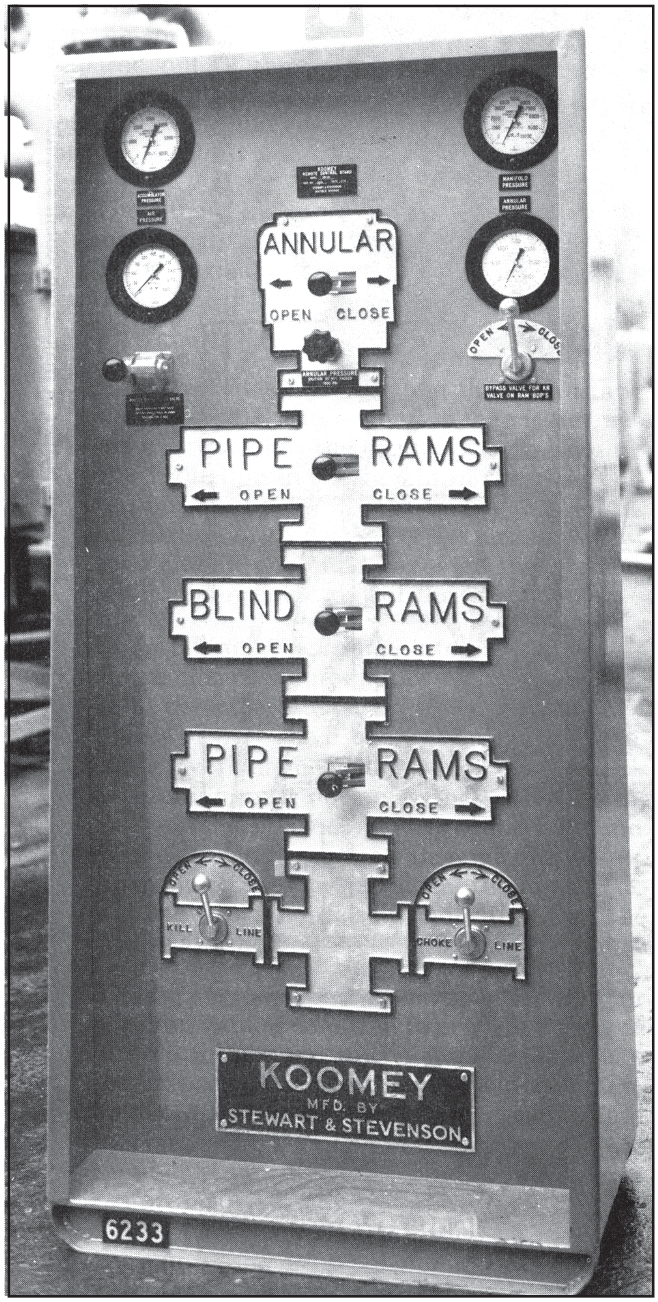
2. The manifold and accumulator unit should be located so they are clearly visible from the rig floor and easily accessible from all directions. An exception to the visibility and accessibility requirements may occur for rigs that are weatherized. These will probably have the accumulator unit located inside a satellite enclosure where it can be protected from the environment. Other exceptions to one or both requirements may be necessary when there is insufficient space at the rig location and when the drilling floor design is incompatible with fulfilling the requirements. However, in all cases, the manifold controls must be located at a safe distance from the well bore, along the primary exit route from the well.

3. All four-way valve handles must be properly installed and maintained for rapid and reliable operation, and each four-way valve must be fully operable by one person without mechanical assistance of any kind. If any type of device has been installed to prevent accidental, manual closing of the CSO rams, this device must not prevent the valve from being operated from a remote station.

4. The function of each four-way valve must be identified by a clearly legible sign, with arrows indicating the direction the handle must be moved to close and open the preventer. The BOP terminology used on the rig should agree with the wording on the identification signs.

5. In both the open and closed position, each four-way valve must be capable of holding the rated working pressure of the accumulator without loss of pressure.

6. All pressure-regulating valves must be fully functional. Also, the pressure gauges on both sides of the pressure-regulating valve of the annular preventer must be functional and accurate.



Pneumatic remote station. A pneumatic remote station is capable of both opening and closing all of the wellhead BOPE. The electric remote station, the type most commonly used in California onshore rigs, can usually be used only to close the equipment. Photo courtesy of *Stewart & Stevenson Oiltools, Inc.*

d. At least one **remote station** must be provided for all Class III and Class IV BOPE installations. These assemblies may be operated electronically, pneumatically, or hydraulically. One of these assemblies must be at the driller's station so the preventers can be closed from the drilling floor.

The remote stations encountered most often in California are electrical and employ a solenoid for each of the four-way valves. When the solenoid-operated valves are actuated, they divert fluid from the accumulator pressure line into a hydraulic cylinder that is attached to the valve-operating handle, thereby driving the handle rapidly to the CLOSE position. Because of the force of this movement, it is important that personnel stay clear of the handles.

On some four-way valves, the position of the operating handle in the OPEN and CLOSE positions may be regulated somewhat by adjusting the threaded fittings on the hydraulic cylinders. This adjustment will sometimes remedy fluid bypassing through the four-way valve.

The general requirements for the remote station are:

1. One station must be within 10 feet of the position occupied by the driller or head well-puller when pipe is being pulled from the hole.

2. Access to this station must be completely unobstructed.

3. Any indicator lights must be in operating condition.

4. The operating lines or cables running from the remote station to the control manifold on the accumulator unit must be protected from potential damage by vehicles or falling objects.

e. **Hydraulic control lines** should be large enough to supply hydraulic fluid rapidly without excessive friction loss, and all control lines must have a pressure rating equal to or greater than the working pressure rating of the accumulator. Additionally, the hydraulic control lines and any component of the control lines such as swivel-joint assemblies installed within 25 feet of the well bore shall be capable of meeting the fire test requirements of the current edition of API Specification 16D. Any flexible hydraulic hose used in the well cellar area must be protected properly from external mechanical damage, and any flexible hoses installed within 25 feet of the well bore must be shielded properly and insulated so the fire test rating meets the current edition of API Specification 16D.

When connecting the control lines to the wellhead equipment, the following procedure may be followed to check for seal-ring leakage in the preventers and to ensure as little air as possible remains in the control lines and the preventer-operating chambers:

1. Drain the hole fluid from inside the stack by opening the valve on the casinghead.

2. Move all of the accumulator unit, control-manifold four-way valves to the NEUTRAL (center) position.

3. Starting with the annular preventer, move the four-way valve for that preventer to the OPEN position. Ensure that the manufacturer's recommended hydraulic pressure is shown on the opening control line.

4. Look down the hole (unless there is any possibility there may be pressure below any preventer) into the preventer stack to ensure there is no leakage of hydraulic fluid into the hole above the packing element of the annular preventer. Leakage would indicate failure of the down-seal ring between the preventer opening chamber and the well bore.

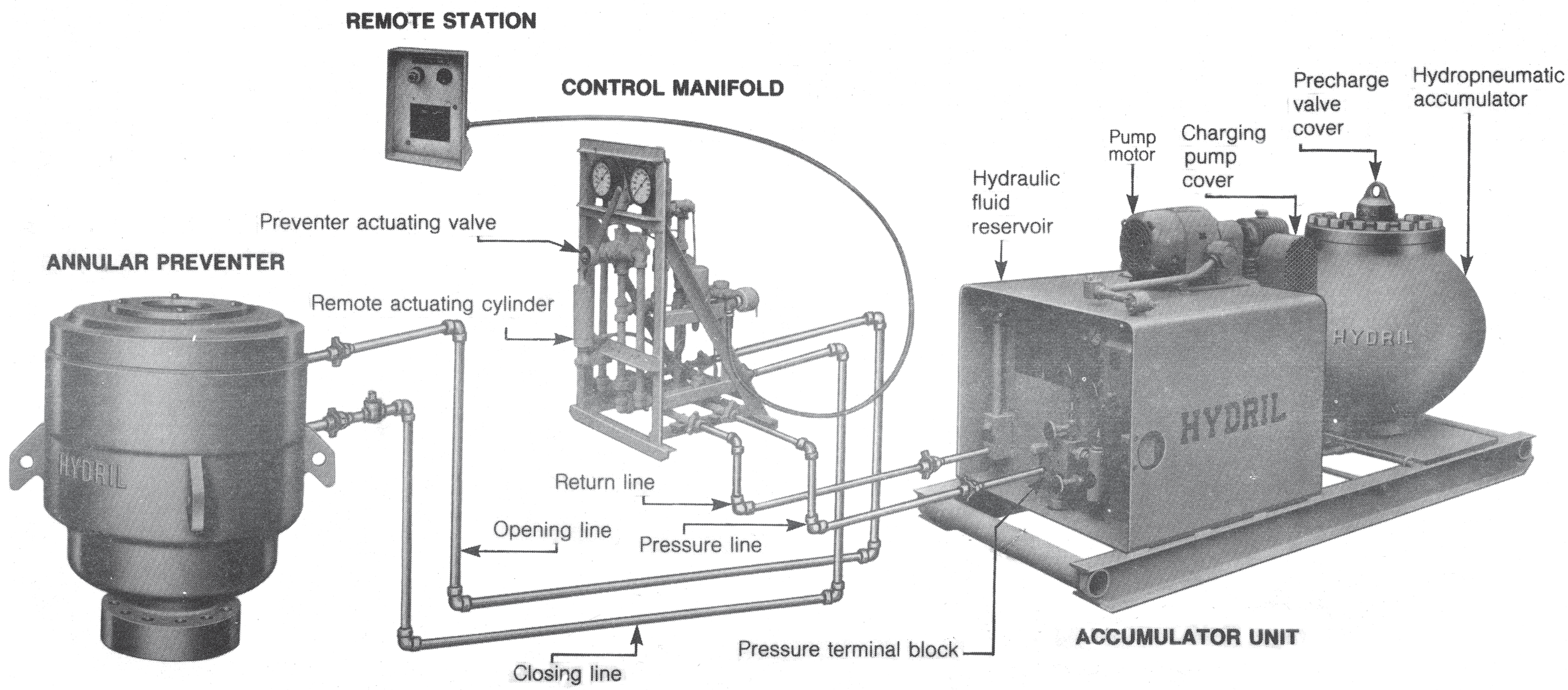
   WARNING: Never look into the well bore if there is any possibility there may be pressure below any preventer.

5. Break the connection closest to the preventer on the closing control line and watch the line from the preventer for flow. Continued flow indicates failure of the up-seal ring on the operating piston between the opening chamber and the closing chamber.

6. Reconnect the closing line (barely hand-tight) and move the four-way valve for that preventer **slowly** toward the CLOSE position to force hydraulic fluid through the line until clean fluid, with no air contamination, is flowing from the loose connection.

7. Return the four-way valve handle to the NEUTRAL position and tighten the connection.

8. Close the preventer on pipe (preferably using the remote station at the driller's position) and repeat Step 4, just discussed, for the OPEN line with pressure in the closing chamber. Check for leakage past the down-seal ring on the operating piston between the closing chamber and the opening chamber. Again, look inside the preventer stack (*see* warning following step 4



Annular preventer and actuating system. Many components mentioned in the text have been labeled. Names of major component assemblies have been capitalized. *Photo courtesy of Hydril Company.*

just discussed) to check for hydraulic fluid leakage that would indicate failure of the upseal ring on the operating piston between the closing chamber and the well bore.

9. Reconnect and tighten the OPEN line. It is not as important to purge air from the OPEN lines as it is from the CLOSE lines, but it can be done (at the operator's option) by repeating Step 6 for each of the OPEN lines.

10. Repeat Steps 2 through 8 for each of the other preventers and hydraulically operated valves to check for seal leaks on the operating piston between the opening chamber and the closing chamber and, in the case of ram-type preventers, on the ram shaft between the opening chamber and the well bore. Do not close the pipe rams on open hole.

f. The **hydraulic fluid** used in the actuating system should possess as many of the following characteristics as practicable:

1. Low compressibility.

2. Low viscosity.

3. Chemical and physical stability over a wide temperature range.

4. Nonpolluting.

5. Noncorrosive.

6. Readily available.

Although fresh water possesses many of the characteristics listed above, it should never be used as a hydraulic fluid in the actuating system unless it is first buffered with a soluble oil additive and, in most cases, a glycol anti-freeze additive in accordance with the supplier's recommendations. Unbuffered fresh water is extremely corrosive when it is moving at the velocities encountered inside the four-way valves, and the valve bodies and rotors can be damaged severely, rendering them useless. If a soluble oil/water mixture is used without an automatic mixing system, care must be exercised to ensure the proportion of oil to water does not drop below the manufacturer's recommended ratio.

Diesel oil is another liquid that should never be used as accumulator hydraulic fluid because of its flammability.

3-4 THE CHOKE AND KILL SYSTEM

The Choke and Kill System is necessary because blowout prevention is seldom a matter of simply sealing the hole at the surface and confining the fluids to the well bore. To do so might cause a downhole pressure buildup that could fracture the formation below the shoe of the anchor string or overpressure a shallow, incompetent formation and permit fluid to come to the surface outside the well bore. If this occurs, regaining control of the well is a difficult and very dangerous process, which is usually extremely costly.

Only by circulating kill-weight fluid at or below the depth of a kick, under carefully controlled pressure conditions, can the kick fluids in the well bore be circulated to the surface, thereby restoring primary control over the formation pressures. Controlling and regulating well-bore pressure while circulating the kill-weight fluid down the working string and up the annulus requires the use of a choke line, manifold, and, in some cases, a kill line.

a. A separate **choke line and manifold** are necessary on Class III, IV, and V BOPE systems to control the back pressure in the well bore and maintain a constant bottom-hole pressure while circulating out a kick.

If manually operated chokes are being used to control the drill pipe pressure (monitored at the standpipe), the manifold area of the choke system should, if practicable, be located so a person stationed at the manifold is visible from the driller's station. This arrangement will facilitate the close coordination required between the two stations. As an alternative in tight locations, a drill pipe pressure-repeater gauge should be mounted at the choke manifold.

If a remotely operated choke is installed, the control station will display both the drill pipe pressure and the casing pressure. In this situation, the choice of location for the choke manifold may be based on convenience rather than visibility from the driller's station.

The choke line and manifold must meet the following requirements:

1. All line pipe used in the choke line must meet the conditions of the current edition of API Specification 5L. If swivel joints are used in the choke line, the joints must be of a long-sweep design and must be mounted out of the cellar and outside of an upward extension of the prism or cylinder formed by the cellar wall(s). A long-

sweep fitting is defined as one in which the radius of curvature of the center line of each turn is greater than the outside diameter of the pipe body.

High-pressure, temperature-resistant flexible choke and kill lines are used frequently in the telescoping joint area of a subsea BOPE system. However, if these lines are to be used on a well utilizing a surface BOP stack on an onshore well, pressure rating must be at least as high as that determined for the BOPE system, and their fire test rating must meet the current edition of API Specification 16C.

The pressure rating of the piping and valves used in the choke line and manifold must be at least as high as that determined for the BOPE system by the method outlined in paragraph 2-6.

With the exception of the wing lines in the choke manifold described in subparagraph 3 that follows, the minimum nominal pipe size should be determined according to the following:

a) 2,000 psi (2M) or lower — 2-inch nominal pipe.

b) Higher than 2M -- 3-inch nominal pipe.

2. All chokes, valves, end connections, and fittings must be made of steel or equivalent material, meeting the conditions of the current edition of API Specification 6A. They must have a rated burst pressure at least as high as that determined for the BOPE system by the method outlined in paragraph 2-6.

3. Requirements for the type of choke line connections will vary with the division's BOPE pressure-rating determination.

a) If the determination is 3,000 psi (3M) or less, threaded connections may be used.

b) All assemblies with a pressure rating above 3,000 psi must be fitted with welded, flanged, or clamped connections only.

4. The straight through (blowdown) line of the choke manifold must be at least the same diameter as the choke line from the well bore to the manifold. The wing lines to the chokes may be 2-inch lines, due to the reduced flow capacity of the chokes, themselves. The blowdown line must be staked down or otherwise secured, to prevent whipping or vibration damage during use.

5. The choke line should follow the most direct, practicable route from the well head to the manifold area.

6. The choke system must be secured wherever necessary, to prevent whipping or vibration damage during use. This is particularly important where swivel joints or flexible lines are used.

7. All changes of direction involving steel lines must be accomplished with welded tube turns, plugged tees, or plugged crosses. No ells are to be used. If tees are used, the plugged or blanked arm must be in line with the arm through which fluid enters the tee during well-choking operations. (Exceptions to this requirement may be approved by the division in developed fields where proven, low, zone pressures would preclude the likelihood of any high-velocity flow during well-killing operations.)

8. All valves in the choke line and manifold must be full-opening valves with straight-through flow design, of at least the same ID as the line to which they are fitted. They must be designed, installed, and maintained for reliable, low-torque operation. In all cases, one valve must be located between the well bore and any changes in direction or hammer unions.

If the BOPE pressure rating determination is 2,000 psi (2M) or less, at least one control valve must be installed as close to the well bore as is practicable.

If the BOPE pressure rating determination is greater than 2,000 psi (2M), double control valves must be installed at the wellhead. The valve closest to the well bore is referred to as the master valve, and the outer valve is referred to as the control valve. Either valve may be remotely actuated.

If the BOPE pressure rating determination is 5,000 psi (5M) or lower, at least one valve must be installed in the wing lines of the choke manifold immediately upstream of each choke, and in the blowdown line. For pressure ratings higher than 5,000 psi, double valves must be installed in the wing lines of the choke manifold immediately upstream of each choke, and in the blowdown line. Where double valves are installed, the master valve should be used only in emergencies, for the operational readiness checks required by paragraph 2-6a3, or for the pressure tests outlined in Section 5 of this manual.

9. The choke manifold must contain an accurate pressure gauge and the required number of chokes. See paragraph 2-6a2 for operational check requirements.

10. Adjustable chokes having a right-angle turn configuration must be installed so fluid passing through the choke exits through the opening in line with the adjusting bonnet. (Note the orientation of the adjustable chokes in Section 2, Figures 4 and 5, for proper installation.)

11. The exit line from each choke must be equipped with a full-closing valve. This valve has two purposes:

    a) The valve may be closed and pressurized to test the integrity of the choke arrangement.

    b) The choke may be isolated from the buffer chamber or any other downstream manifold arrangement, so each choke may be removed from the system without affecting the usefulness of the rest of the choke manifold.

b. A separate **kill line** is required for Class III, IV, and V BOPE so weighted fluid can be pumped into the annular space of the well bore to replace lost fluid, to establish reverse circulation while the preventers are closed, or to circulate gas out of a subsea BOP stack and fill the riser with kill-weight mud before opening the preventer stack entirely.

   This kill line should not be used for routine hole-filling operations because the fittings may be damaged by abrasion or improper use. This is a pressure line and must fulfill the following requirements:

   1. All lines and fittings must have a minimum OD of two inches and a rated pressure greater than, or equal to, the pressure rating of the BOPE system as determined in paragraph 2-6.

   2. The portion of the kill line located in the cellar and rig substructure area must be made of steel or equivalent material approved by the division. All line pipe used in the kill line must meet the conditions of the current edition of API Specification 5L. If swivel joints are used in the kill line, the joints must be of a long-sweep design and mounted out of the cellar and outside of an upward extension of the cellar walls. A long-sweep fitting is defined as one in which the radius of curvature of the center line of each turn is greater than the outside diameter of the pipe body.

   3. Steel end connections and fittings must meet the conditions of the current edition of API Specification 6A.

      High-pressure, temperature-resistant flexible choke and kill lines are used frequently in the telescoping-joint area of a subsea BOPE system. However, if these lines are to be used on a well utilizing a surface BOP stack or on an onshore well, pressure rating must be at least as high as that determined for the BOPE system, and then fire test rating must meet the current edition of API Specification 16C.

      The pressure rating of the piping and valves used in the choke line and manifold must be at least as high as that determined for the BOPE system by the method outlined in paragraph 2-5.

   4. Requirements for connections will vary with the division's BOPE pressure-rating determination.

      a) If the determination is 3,000 psi (3M) or less, threaded connections may be used.

      b) All assemblies with a pressure rating greater than 3,000 psi must be fitted with welded, flanged, or clamped connections only.

   5. Where flexible pressure hoses are used away from the well head, all hose connections must be provided with safety chains and the hose, itself, protected from external damage.

   6. All changes of direction involving steel lines must be accomplished with welded tube turns, plugged tees, or plugged crosses. No ells are to be used. If tees are used, the plugged or blanked arm must be in line with the arm through which fluid enters the tee during well-killing operations. (Exceptions to this requirement may be approved by the division in developed fields where demonstrated, low zone pressures would preclude the possibility of high pressures in the kill line during well-killing operations.)

   7. All valves in the kill line, with the exception of the check valve, must be full-opening valves with straight-through flow design and at least the same ID as the line to which they are fitted. They must be designed, installed, and maintained for reliable, low-torque operation. In all cases, one valve must be located between the well bore and any changes in direction or hammer unions.

If the BOPE pressure rating determination is 3,000 psi (3M) or less, at least one control valve must be installed as close to the well bore as is practicable.

If the BOPE pressure rating determination is greater than 3,000 psi (3M), double control valves must be installed at the wellhead. The valve closest to the well bore is referred to as the master valve, and the outer valve is referred to as the control valve. Where double valves are installed, the master valve should be used only in emergencies, for the operational readiness checks required by paragraph 2-6a3, or for the pressure tests outlined in Section 5 of this manual.

8. On surface BOPE systems, a check valve must be installed on the pump side as close to the control valve as is practicable.

9. An access port must be provided for connection of an auxiliary pump. This port should be readily accessible if it becomes necessary to replace or supplement the rig pumps.

3-5 AUXILIARY EQUIPMENT

Auxiliary equipment, which cannot be functionally grouped with the equipment just described, must also be included in a BOPE classification. The equipment consists of items installed in, or available to be installed in, the drill string and into the pitcher nipple above the preventers.

a. The **fill-up line** does not function in any remedial capacity after a kick occurs (as the rest of the auxiliary equipment does). Nevertheless, it is of prime importance in kick prevention.

   Many kicks take place when the hydrostatic overbalance at the formation face is permitted to drop below the required value because of a reduction in the height of the fluid column in the hole. This can be caused by lost circulation or by failure of the drilling crew to maintain the fluid level within the required limits while pulling pipe out of the hole.

   By installing a pump line into the bell nipple above the preventers and using this line to refill the hole after a prescribed number of stands of pipe have been pulled, the hydrostatic overbalance can be maintained. The fill-up line must not enter the bell nipple at a point opposite the opening of the flow line. If it does, fluid pumped through the fill-up line would be propelled across the nipple and out of the flow line, indicating falsely that the hole was full.

   The rig foreman, the operator's representative, or some other supervisor must compute the number of pump strokes required to provide a volume of hole fluid equal to the displacement of a number of stands prescribed by the operator. The maximum number of stands to be pulled before refilling the hole and the computed number of pump strokes required to refill the hole must be posted on the driller's console near the pump stroke counter, if any. Possible downhole pressure irregularities can be detected by comparing this computed number with the number of pump strokes actually required to restore circulation at the flow line while pulling pipe. The repeated necessity for more than the computed number of pump strokes indicates lost circulation, while the necessity for fewer than the computed number is a strong indication of fluid entry. In either case, established kick-control procedures should be initiated.

b. The **standpipe** is an important part of any Class III, IV, or V BOPE assembly because of its position in the circulating system and its proximity to the driller's station, which is often the center for kick-control operations. A pressure gauge must be installed so the fluid pressure inside the drill pipe can be monitored and regulated by adjusting the pump speed or choke settings. A valve must be installed between the standpipe pressure gauge and the mud pumps so a shut-in drill pipe pressure can be obtained.

c. **Kelly cocks** are full-open valves mounted in the kelly assembly that may be closed quickly to protect the rotary hose and swivel from pressure damage in the event of a kick. In Class II installations, where high pressures are unlikely, the kelly cock is unnecessary if a standpipe valve has been installed between the standpipe pressure gauge and the circulating pump(s). In Class III installations, either an upper or a lower kelly cock must be used. For Class IV and V, both upper and lower kelly cocks must be installed on the kelly at all times. If a downhole mud motor is to be used, kelly valves must be installed at the top and at bottom of the joint of pipe used in lieu of the kelly. If a top drive system is in use, a remotely operated kelly valve must be installed just below the drive mechanism and a manually operated kelly valve must be installed at the bottom of the uppermost joint of drill pipe (where it will be accessible from the rig floor by raising the drill string prior to shutting in the well). The operating wrench(es) must be accessible and the location(s) known to all members of the crew.

All lower and upper kelly cocks are full-closing valves, and most will hold pressure either from above or below. However, an upper cock is available that employs a handle-operated flapper valve that will open when pressured from above. For this reason, and because of possible pressure damage to the mud hose and swivel, *all kelly cocks should be pressure tested in the direction of blowout flow.*

d. A **pipe safety valve** is a full-opening valve that may be stabbed into the pipe string in the presence of flow up the pipe and then closed, permitting easy installation of the kelly or the internal preventer. A recommended procedure is to make up the safety valve on the bottom of a joint of pipe and place the joint in the mouse hole or some other readily available position during trips. If flow occurs unintentionally, this joint may be picked up quickly in the elevators and stabbed into the pipe string. Then the safety valve can be closed, the joint backed off above the valve, and established kick-control procedures initiated.

Once the safety valve has been installed, it may be opened or closed at will, as long as it remains above the drilling floor, but it cannot be removed while there is pressure in the pipe string. For this reason it must be of such a configuration and OD that it can be stripped through the preventers in use and enter any casing in the hole that must be passed through to establish circulation at any point of fluid entry. Adapters may be necessary to allow quick attachment of the safety valve to any pipe that will be used in the proposed operations.

When casing is being run, this valve will probably be of the slip-on type that clamps over a casing collar. If this type of valve is to be used, the crew must perform an actuation test of the valve before starting to run casing.

The rig crew members must be trained in the use of this valve, and they must understand that while tripping the pipe, the pipe safety valve, not the internal preventer, which will be described in paragraph e., **will be the first piece of equipment** they will attempt to stab into the drill string in the event of a kick.

e. An **internal preventer** (inside blowout preventer) is defined as a check valve in the drill string that permits circulation down the hole, but prevents any back flow. Many field personnel do not understand the difference in application between the pipe safety valve and the internal preventer, feeling that both serve the same purpose and no need to provide both exists. However, the pipe safety valve, being a full-closing valve, does not fit the definition and cannot be accepted as an internal preventer.

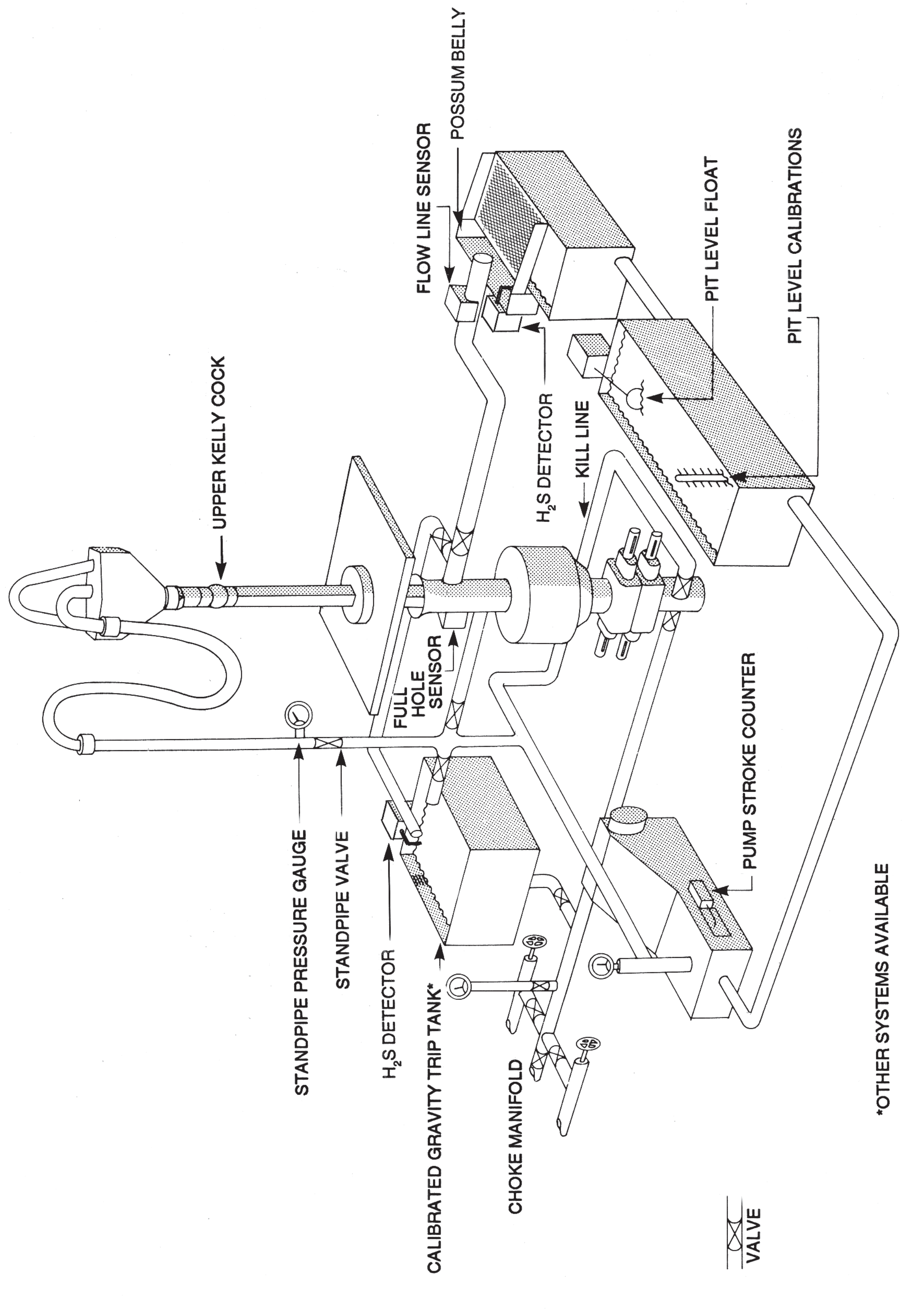
Float valves installed at the bottom of the drill string, or drop-in pump-down check valves, serve the same purpose, but are often prohibited by operators because of the restrictions they place on other operations.

Surface-mounted internal preventers are those devices kept in a ready position near the rig floor and, if needed, are stabbed into the pipe string at any point and stripped into the hole. This operation requires the valve to be open normally, capable of being closed quickly, and of such configuration and OD that it can be stripped through the preventers in use and enter any casing in the hole that must be passed through to establish circulation at any point of fluid entry. In some cases, adapters must be provided to permit the quick attachment of the internal preventer to the safety valve just described in paragraph 3-5d.

The internal preventer must be stored in such a location, or identified distinctively, so it **will not be** the first valve the crew installs when a kick is taken while tripping pipe.

3-6 HOLE-FLUID MONITORING EQUIPMENT

Hole fluid monitoring equipment (Fig. 12) is needed to detect, as soon as possible, significant changes in the fluid volume and, in some cases, the physical properties of the hole fluid. The hole fluid that is used during drilling or workover operations exerts pressure directly against the formation and is the primary means of preventing blowouts. Any irregularity at the formation face will cause meaningful changes in the fluid system that may be measured at the surface. These changes may be very subtle at first, and a busy drilling crew can easily overlook or attach little significance to them until the changes have magnified to the point that control is difficult. To permit the detection of subtle fluid-system changes, one of the following classes of monitoring equipment may be required.



SIMPLIFIED HOLE FLUID CIRCULATING SYSTEM
WITH MONITORING DEVICE LOCATIONS

FIGURE 12

a. **Class A.** Any device capable of a reasonably accurate determination of fluid-system gains and losses, such as a reference mark or calibrations in the mud pit, easily seen from the driller's station, that will clearly indicate a change from the normal fluid level of the pit. When pulling pipe, the driller must be able to determine if the hole requires an abnormal volume for refill by relating changes in pit level to pipe displacement.

b. **Class B**

1. Mud-pit level indicator with audible alarm, such as a level-sensing device in the mud pit, with an indicator at the driller's station. The indicator may show a reference level or a change in level. The device must provide an audible alarm, indicating any abnormal change in fluid level.

2. Any device capable of a reasonably accurate determination of the volume of fluid required to keep the hole full while pulling pipe, such as a pump-stroke counter or indicator, trip tank, or fill-volume meter to measure the fill volume required while pulling pipe. Such a device will detect swabbing or lost-circulation conditions (see paragraph 3-5a).

c. **Class C**

1. A recording, mud-pit level indicator to denote abnormal mud-pit volume gains and losses with both visible and audible warning devices, such as a level-sensing device in the mud pit with a continuous recording chart at the driller's station to provide a clear measurement of pit-level changes.

2. A mud-volume measuring device for accurate determinations of the mud volumes required to maintain the fluid level at the surface while pulling drill pipe from the hole. These include a pump-stroke counter, providing a readout at the driller's station, or a trip tank or flow meter with a volume indicator clearly visible from the driller's station.

3. A mud-return or full-hole indicator to indicate when there are mud returns and determine whether returns essentially equal the pump-discharge rate, such as a flow indicator in the mud-return line (flow line) or a device that senses the fluid level in the bell nipple to detect the unintentional flow of mud from the well or lost circulation. An audible alarm must be provided.

4. Gas-detection equipment to monitor the drilling-mud returns for hydrocarbons and (where needed) hydrogen sulfide (H_2S) gases at critical locations along the mud system.

3A. SUBSEA BOPE INSTALLATION

3A-1 GENERAL

When offshore drilling is performed from any floating structure or vessel (such as a semisubmersible platform or drill ship), the BOP stack must be installed on the ocean floor. The stack components used in these subsea BOPE arrays are similar or identical to those used in surface installations, but include additional auxiliary equipment and considerable modification of the actuating system components. This equipment is described in the current edition of *Recommended Practices for Blowout Prevention Equipment Systems, API RP 53*, together with any supplements. Portions of the publication are included in this manual.

One of the differences between surface and subsea BOPE requirements is the need for system redundancy. All systems of a subsea BOPE array must be designed so alternative methods of well control are available in the event of failure of any portion of the system. If it is determined that any component of the BOPE system has become inoperative, drilling operations must be suspended as soon as it is safe to do so, and remain suspended until the inoperative equipment is repaired or replaced.

3A-2 THE DIVERTER SYSTEM

a. **Purpose**. During the early stages of drilling an offshore well, when the sea floor surrounding the well bore is highly susceptible to fracturing, a diverter system, instead of preventers, should be employed in a well control situation.

Instead of shutting in a well, the diverter system packs off the annular space around any component of the working string. A system of valves and vent lines in the diverter system directs flowing fluids away from the rig floor. This provides a degree of protection for the rig and crew in the event of a kick taken prior to setting the casing string to which the preventer stack and the choke/kill manifold will be attached.

The diverter system will also permit the crew to safely clear the BOPE stack of any gas that would collect under closed preventers during a kick circulation.

b. **Installation and Equipment Requirements**

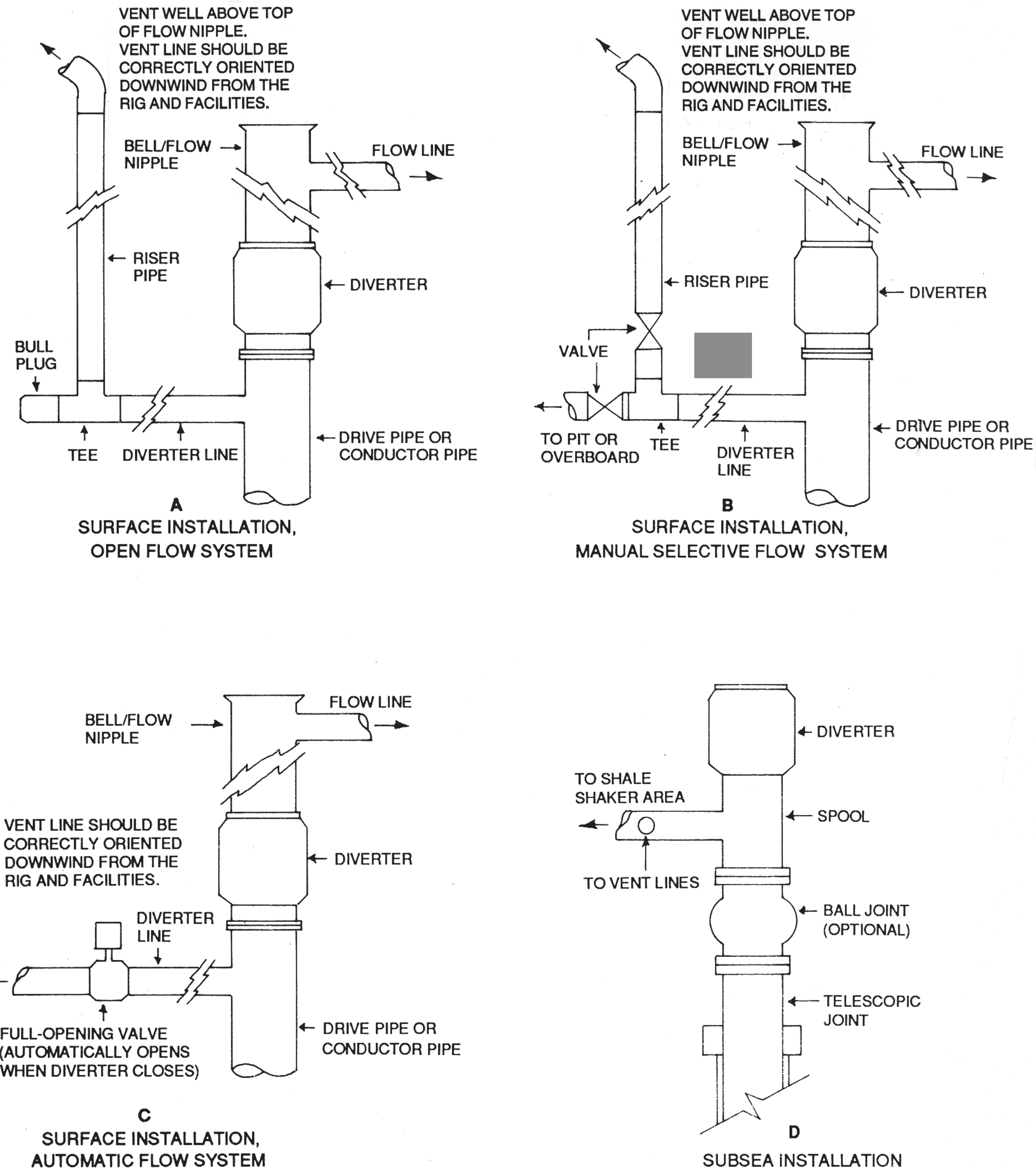
1. **Casing**. When drilling offshore, the first string of casing (known as the conductor, drive, or structural casing) is cemented or driven below the mud line. The formation at the shoe of this casing string must be capable of withstanding the hydrostatic pressure of the riser full of drilling fluid, together with any reasonable circulating pressures involved, until the next string of casing (first surface casing) is cemented in place.

2. **Positioning the Diverter System**. A diverter system must be installed on the well prior to drilling below the shoe of the conductor casing. After the conductor has been set, a marine riser system is attached to the wellhead. The diverter system is then connected to the top of the marine riser and secured to the rig substructure.

3. **The Diverter**. The diverter itself must be either a specially designed low-pressure diverter (Fig. 13) or a conventional annular preventer or rotating head. The diverter must have a throughbore capable of passing any tools to be used until the first surface casing has been cemented in place.

4. **Vent Lines**. There must be at least two diverter vent lines to permit diversion of well fluids while minimizing back pressure on the well. All vent lines in offshore diverter systems inspected by the division must have a minimum 8-inch nominal diameter, unless otherwise justified by engineering analysis. The vent lines leading from the diverter must be directed to opposite sides or ends of the drilling structure or vessel, so downwind diversion may be selected (Fig. 14).

5. **Valves**. All valves on the diverter vent lines must be full-opening and the system must be designed so the proper valve either opens automatically when the diverter is activated or can be opened by remote control from the driller's station. These valves may be equipped with a fail-safe-open operator, but in all cases, at least one vent line must be open at all times.

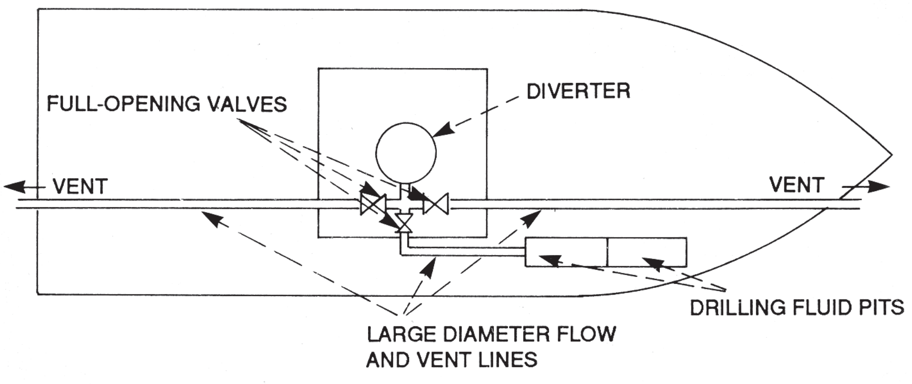


TYPICAL DIVERTER SYSTEMS

FIGURE 13

6. **Working Pressure.** The rated working pressure of the diverter and vent line(s) is not particularly important because the purpose of the system is to divert, not contain, wellbore fluids.

7. **Actuation and Drills**. The diverter and any associated vent-line selection valves should be actuated when installed and at least once each week during well operations to ensure the system will function properly. During any drilling operations that require the diverter to be used instead of preventers, the required weekly diverter-operation practice drills must be held.



TYPICAL DIVERTER LAYOUT, SUBSEA INSTALLATION

FIGURE 14

8. **Maintenance**. Clean water should be pumped through each diverter and vent line at appropriate times during operations. This ensures the line(s) are not plugged with drill cuttings or other debris.

3A-3 THE BLOWOUT PREVENTER STACK

a. **Variance from Surface Installations**

1. Choke and kill lines are manifolded at the surface to accommodate fluid flow in either direction. Normally, the kill line does not have the check valve that is required in surface BOPE installations as it is often desirable to use either line as a kill or a choke line--singly or in combination.

2. One ram-type preventer in each subsea BOPE installation must contain blind/shear rams. The blind/shear rams must be installed in the uppermost ram-type preventer unless the operator's operating practices call for the installation of a set of regular CSO rams above them. Having the blind/shear rams at or near the top of the stack will permit the working string to be supported by hangoff rams before shearing is attempted. Proper pipe-ram positioning and ram-block selection will allow the drill pipe to be hung off on a tool joint so the working string is supported after the string has been sheared. Consideration should be given to the design of the ram blocks, themselves, if the preventer is to be used for hang-off. The 18-degree taper found at the upper edge of the pipe opening in a normal ram block might not support a large pipe load. Ram blocks designed for hang-off have a hardened, square-shouldered insert in place of the taper.

3. Ram preventers are equipped with automatic or remotely operated locking systems.

4. Ram preventer bodies may have provisions for up to three sets of rams in one body.

b. **API Stack Component Codes**. The recommended component codes adopted by the American Petroleum Institute for designation of subsea blowout preventer stack arrangements are the same as those for surface installations, with the addition of remotely operated connectors.

C_H = A high-pressure, remotely operated connector used to attach the preventer stack to the wellhead or the preventers to each other. (The connector must have a minimum working-pressure rating equal to the preventer stack working-pressure rating.)

C_L = A low-pressure, remotely operated connector used to attach the marine riser system to the blowout preventer stack.

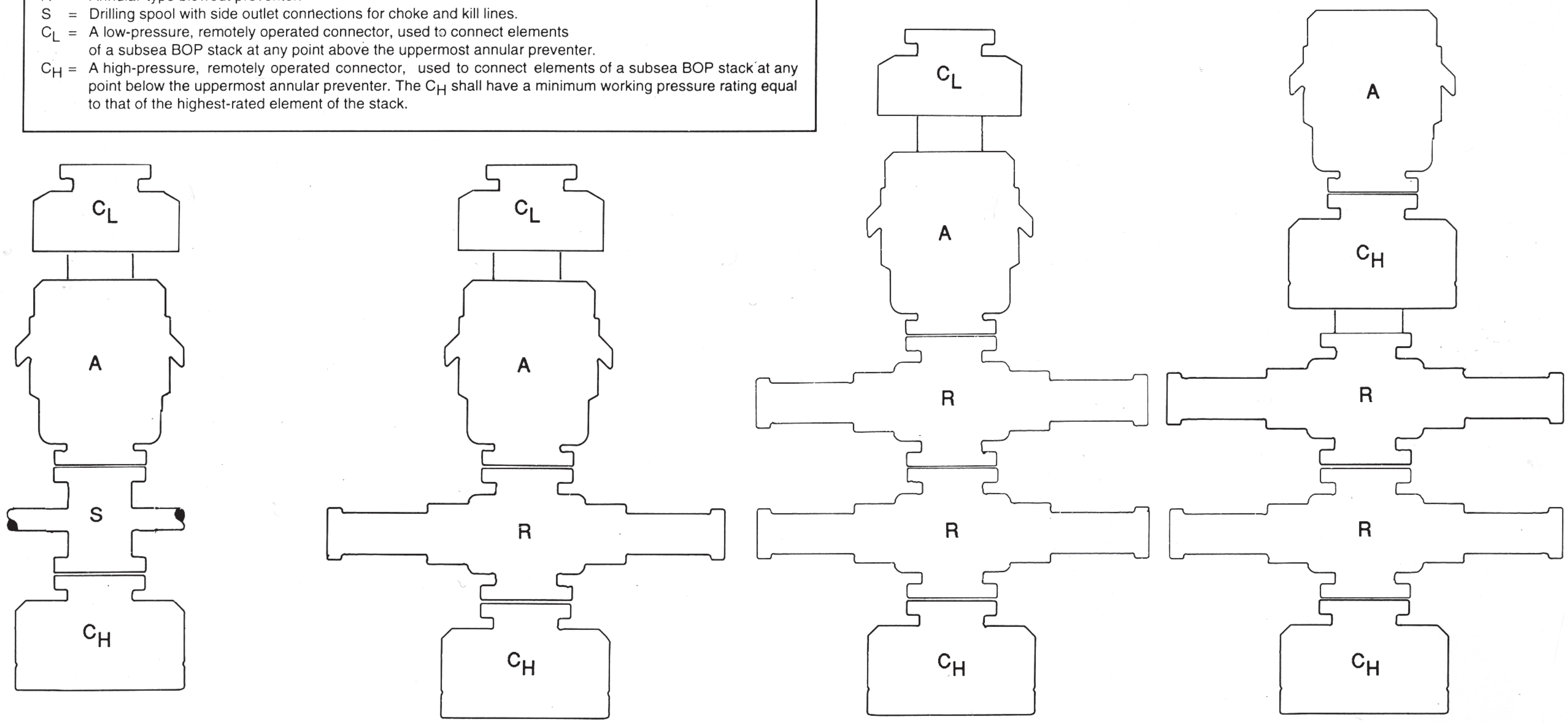
c. **Stack Arrangements**. For subsea BOPE installations, the minimum requirements for annular and ram-type preventers will vary, depending on the string of casing that is serving as the BOP anchor string:

ANCHOR STRING	BOP REQUIREMENTS
Conductor, Drive, or Structural	1 Diverter System
First Surface Casing	1 Annular
	1 Blind-shear Ram
	1 Pipe Ram
Second Surface Casing and All Subsequent Strings	2 Annular
	1 Blind-shear Ram
	3 Pipe Rams

d. **Pressure Rating Requirements**. All components of the BOPE system must have a working pressure

API BOP-STACK ARRANGEMENT LEGEND

R = Single-ram-type preventer with one set of rams, either blank or for pipe.
Rd = Double-ram-type preventer with two sets of rams, positioned in accord with operator's choice.
A = Annular-type blowout preventer.
S = Drilling spool with side outlet connections for choke and kill lines.
C_L = A low-pressure, remotely operated connector, used to connect elements of a subsea BOP stack at any point above the uppermost annular preventer.
C_H = A high-pressure, remotely operated connector, used to connect elements of a subsea BOP stack at any point below the uppermost annular preventer. The C_H shall have a minimum working pressure rating equal to that of the highest-rated element of the stack.



A — ARRANGEMENT C_HSAC_L
2M rated working pressure only)

B — ARRANGEMENT C_HRAC_L

C — ARRANGEMENT C_HRRAC_L

D — ARRANGEMENT C_HRRC_HA

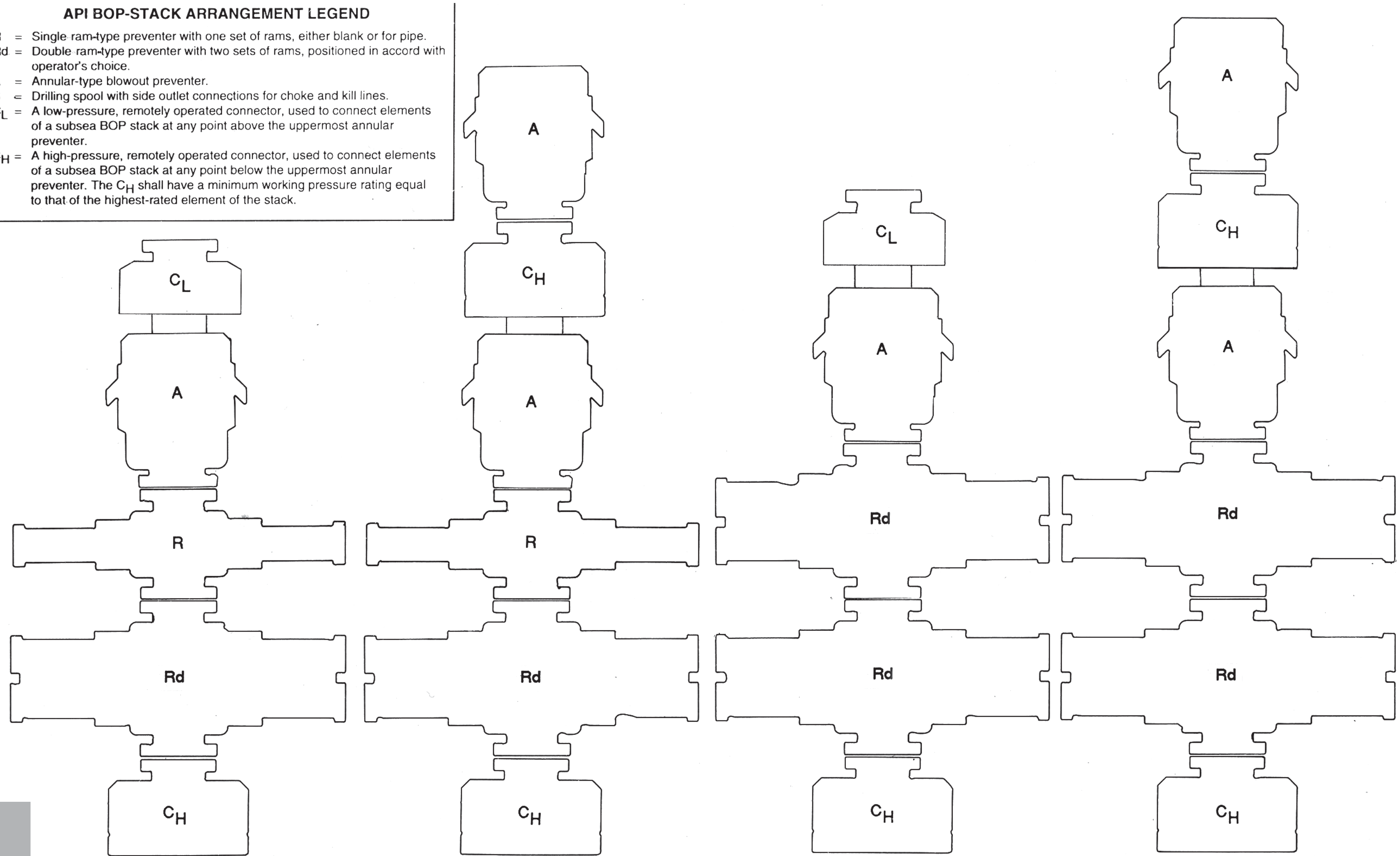
Double Ram-type Preventers, R_d, Optional

TYPICAL BLOWOUT PREVENTER ARRANGEMENTS FOR 2M AND 3M RATED WORKING PRESSURE, SUBSEA INSTALLATION

FIGURE 15

API BOP-STACK ARRANGEMENT LEGEND

R = Single ram-type preventer with one set of rams, either blank or for pipe.
Rd = Double ram-type preventer with two sets of rams, positioned in accord with operator's choice.
A = Annular-type blowout preventer.
S = Drilling spool with side outlet connections for choke and kill lines.
C_L = A low-pressure, remotely operated connector, used to connect elements of a subsea BOP stack at any point above the uppermost annular preventer.
C_H = A high-pressure, remotely operated connector, used to connect elements of a subsea BOP stack at any point below the uppermost annular preventer. The C_H shall have a minimum working pressure rating equal to that of the highest-rated element of the stack.



A
ARRANGEMENT $C_HR_dRAC_L$
Triple Ram-type Preventers, R_t, Optional.

B
ARRANGEMENT $C_HR_dRAC_HA$

C
ARRANGEMENT $C_HR_dR_dAC_L$

D
ARRANGEMENT $C_HR_dR_dAC_HA$

TYPICAL BLOWOUT PREVENTER ARRANGEMENTS FOR 5M, 10M, AND 15M RATED WORKING PRESSURE, SUBSEA INSTALLATION

FIGURE 16

rating that exceeds the anticipated pressures to which they may be subjected. The working pressure rating of all valves, lines, and fittings must equal or exceed the rating of the ram-type preventers. Along with each well proposal, the operator must submit the maximum predicted casing pressure for each casing string and the method of determining the pressure.

Notwithstanding the working-pressure requirements determined previously, all blowout preventers that are used while drilling the hole for surface or intermediate casings must have a minimum working-pressure rating of 2,000 psi (2M). This pressure requirement does not apply to the components of diverter systems used on the conductor casing.

e. **Pipe Stripping Arrangements.** To provide for the maximum utility of the entire BOPE system, the subsea stack arrangement should make provisions for stripping pipe. Pipe stripping is the process of running or pulling drill pipe, casing, or tubing with one or more of the blowout preventers closed. To facilitate stripping operations, the following should be considered:

1. Drilling spool and ram preventer placement. Precise measurements of the blowout preventer stack, particularly the space available between two adjacent sets of pipe rams, should be posted at the driller's control panel. If ram-to-ram stripping is anticipated, the inter-ram space must accommodate the combined length of the pin and box upsets of a tool joint. This upset length will vary between 15" and 18-1/2", depending on the size and grade of the drill pipe in use. See Table 4.2, API Specification 7, for a listing of these lengths.

2. The closing-pressure regulator valve for the annular preventer must be responsive to pressure variations of less than 100 psi within the preventer, or a surge accumulator should be installed in each of the annular preventer operating lines. Before running the preventer stack, the precharge pressure of these surge accumulators should be determined and set for the specific rig and well conditions, such as seafloor temperature and water depth.

3. The choke manifold should have a vent to the trip tank for accurate fluid-volume measurements while stripping.

4. Acceptable limits of vessel motion, drill pipe motion, and well pressure should be established. If observed values exceed the limits, stripping should not be performed.

3A-4 SUBSEA ACTUATING SYSTEM

a. **Variance from Surface Installations**

1. More accumulator volume is normally required.

2. Some of the accumulator bottles may be mounted on the subsea blowout preventer stack.

3. Consideration must be given to the environmental qualities of the hydraulic operating fluid because it will be disposed of on the ocean floor. It must be nonpolluting and nontoxic to marine life.

b. **Accumulator Units**

1. ***Volumetric Capacity*** **-** As a minimum requirement, closing units for subsea installations must be equipped with accumulator bottles with sufficient capacity to provide the necessary usable fluid volume (with pumps inoperative) to open and close the ram preventers and one annular preventer. (The usable fluid volume is defined as the volume of fluid recoverable from an accumulator between the operating pressure and 1,000 psi, or 200 psi above the precharge pressure, whichever is greater.) For the sizing of surface-mounted accumulator units, refer to Appendix F.

   The accumulator system must have the capability to close each ram-type preventer within 45 seconds. Closing time for the annular preventer(s) must not exceed 60 seconds.

   In selecting the total volume for the subsea-mounted accumulator bottles, the additional precharge pressure required to offset the hydrostatic head of the seawater column and the effect of subsea temperature must be considered.

2. ***Accumulator Bank Isolation Valves*** **-** Multibottle accumulator banks should have valving for bank isolation. The isolation valves should have a rated working pressure at least equal to the designed working pressure of the system to which they are attached. The valves in the active accumulator banks must be in the open position, except when the accumulators are isolated for servicing, testing, or transporting. If one or more of the accumulator banks are to be used as

the backup system for the accumulator unit, the isolation valves to those banks are to be maintained in the closed position, unless the banks are in use or are being charged or precharged.

3. ***Accumulator Types*** **-** Either separator or float-type accumulators, or a combination of the two, may be used.

c. **Hydraulic Fluid Mixing System**. The hydraulic fluid reservoir must be a combination of two storage sections: one section containing mixed fluid to be used in the operation of the blowout preventers and another section containing the concentrated, water-soluble hydraulic fluid that is combined with water to form the mixed hydraulic fluid. This mixing system must be controlled automatically so the mixing system will turn on the water and the proper ratio of hydraulic-fluid concentrate will be mixed with it and pumped into the mixed-fluid reservoir when the mixed-fluid reservoir level drops to 75 percent of its full volume. The mixing system must be designed to mix at a rate at least equal to the total pump output, and the mixed-fluid reservoir must have a capacity equal to twice the usable fluid capacity of the accumulator system.

d. **Accumulator Charging Pumps**. A subsea closing unit control system must include a combination of air and electric pumps. A minimum of two air pumps must be included in all systems, along with one or two electric-powered multiplex pumps. The combination of air and electric pumps must be capable of charging the entire accumulator system from the precharge to its rated working pressure in 15 minutes or less. Each pump system must have an independent, alternative power source.

The pumps must be equipped with automatic switches that activate the pumps when the accumulator line pressure drops to 90 percent of the rated working pressure of the accumulator unit.

With the accumulator banks isolated from the rest of the actuating system, each charging pump system must be capable within two minutes of closing the annular preventer on the drill pipe being used, opening the hydraulically-operated choke-line valve, and obtaining a minimum pressure of 200 psi above the accumulator precharge on the closing unit manifold.

e. **The Hydraulic Control System**. Normally, the hydraulic control system consists of two sections:

1. A power-fluid section that sends hydraulic fluid to subsea equipment.

2. A pilot section that transmits signals to the subsea control pods via pilot lines.

When a valve on the control manifold is operated, a signal is sent subsea via the pilot section to a control valve that, when opened, allows hydraulic fluid from the power-fluid section to operate the blowout preventers. Pressure regulators on the surface-control manifold send pilot signals to subsea regulators to control the pressure of the hydraulic fluid at the preventers.

f. **The Electrohydraulic Control System.** An electrohydraulic system has a central control point where various signals interface electronically. Electrical signals are sent to the subsea solenoid valves, which direct the flow of hydraulic fluid to operate a blowout preventer function. In this system, a flow meter must be used to provide an indication of the proper flow of hydraulic fluid and proper operation of the blowout preventer.

g. **The Control Stations**. A subsea closing-unit control system must have a master control panel at a central control point that is safely outside the cone of danger around the well bore and readily accessible to the drilling personnel in an emergency. The master control panel must be capable of operating and monitoring all of the functions of the closing-unit system. All of the controls and gauges in the panel must be marked clearly and arranged in the same orientation as the valves and other equipment they control in the blowout preventer stack.

In addition to the master control panel, additional control panels must be located at the driller's station and at a strategic, remote location (at least 50 feet from the well bore) for emergency use. The division requirements for these control panels are:

1. Each panel must be capable of operating all of the functions of the closing-unit system.

2. Each panel must have a schematic outline of the blowout preventer stack, with the control devices in the proper orientation relative to one another.

3. The panel must be equipped with a flow meter that measures the flow of actuating fluid to the subsea equipment. This meter will serve as an indication that a component is operating by measuring the volume of fluid going to that component.

4. Each panel must provide for remote panel activation.

5. Each panel must have a power source independent of the accumulator pump system, or be designed so complete destruction of the panel or interconnecting cable or hose will not interfere with the operation of the accumulator pump system.

h. **Hose Bundles and Hose Reels.** The control hose bundles may be designed for either hydraulic or electrohydraulic control of the subsea stack.

In a hydraulic control system, small-diameter pilot hoses transmit operating signals to subsea valves on the blowout preventer stack, while hydraulic operating fluid for the preventers, connectors, and valves is supplied through a power hose or rigid line to the control pods or to accumulators on the blowout preventer stack. The pilot hoses must have a minimum internal diameter of 3/16 inch and the power hose must have a minimum internal diameter of 1 inch.

In an electrohydraulic system, electrical cables transmit operating signals to solenoid valves in the subsea stack control pods. The hydraulic power supply line may be integrated into the electrical cable bundle or may be run separately.

The hose reels should be designed so some BOP stack functions are operable while running or pulling the stack or marine riser package. During such times, it is recommended that the following components be operable: the stack connector; the riser connector; and the control-pod latches.

i. **Subsea Control Pods**. There must be two completely redundant control pods on the lower marine riser package after the BOPE stack has been installed. Each control pod must contain all of the valves and regulators necessary to operate all of the blowout preventer stack and lower marine-riser package functions. The hoses from the base plates for each control pod lead to a series of shuttle valves that are connected to the components of the BOP stack. A shuttle valve is a slide valve with two inlets and one outlet, permitting operation of the preventers or other function from either control pod, while preventing hydraulic fluid movement between the pods. The control pods may be retrievable separately from the lower-marine riser package.

3A-5 CHOKE/KILL LINE VALVE AND PIPING ASSEMBLIES

a. **Riser Line Types**. Choke and kill lines for subsea installations must be 3-inch nominal diameter or larger and are usually installed opposite one another on the exterior of the marine riser. These lines are of three types: integral, track, or funnel (Fig. 17).

1. The integral type has the lines permanently connected to each marine riser joint, with pin and box connectors stabbed and made up simultaneously with the riser connector.

2. The track type has two guide rails installed permanently on the marine riser that offer guidance for skates attached to choke and kill lines. The choke and kill lines are run after the riser has been installed.

3. The funnel type has funnels attached to the marine riser that also permit choke and kill lines to be run after the riser is installed.

b. **Wellhead Piping and Valves**

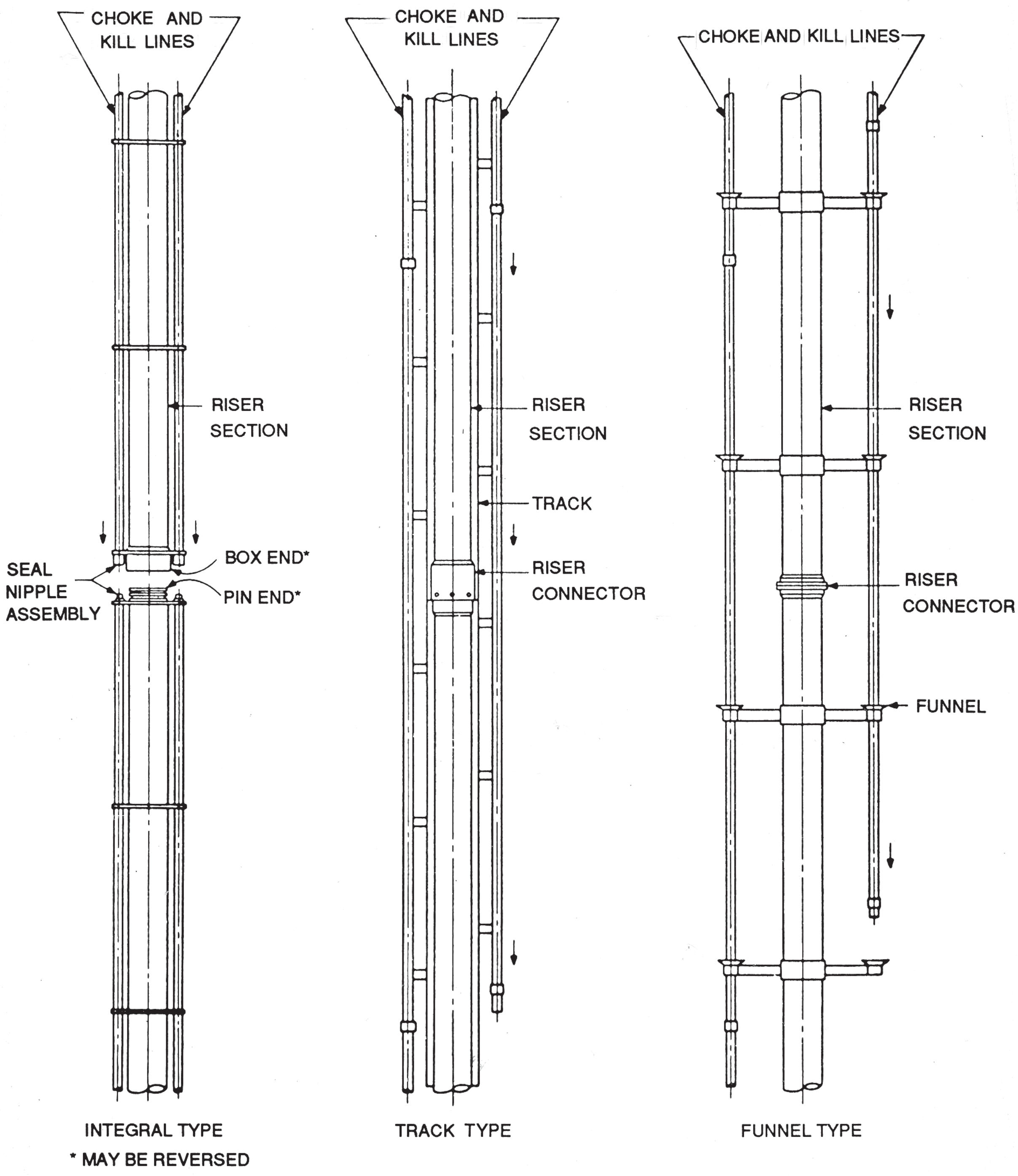
1. All functions of the choke and kill lines for subsea BOPE assemblies should be interchangeable; therefore, any requirements for the choke line apply to the kill line.

2. Each choke line and kill line must have at least two remotely operated valves positioned at the BOP stack.

3. The body of the innermost (master) valve must be attached directly against the blowout preventer body outlet and must be of a fail-safe-close design. Normally, this valve will be maintained in the closed position.

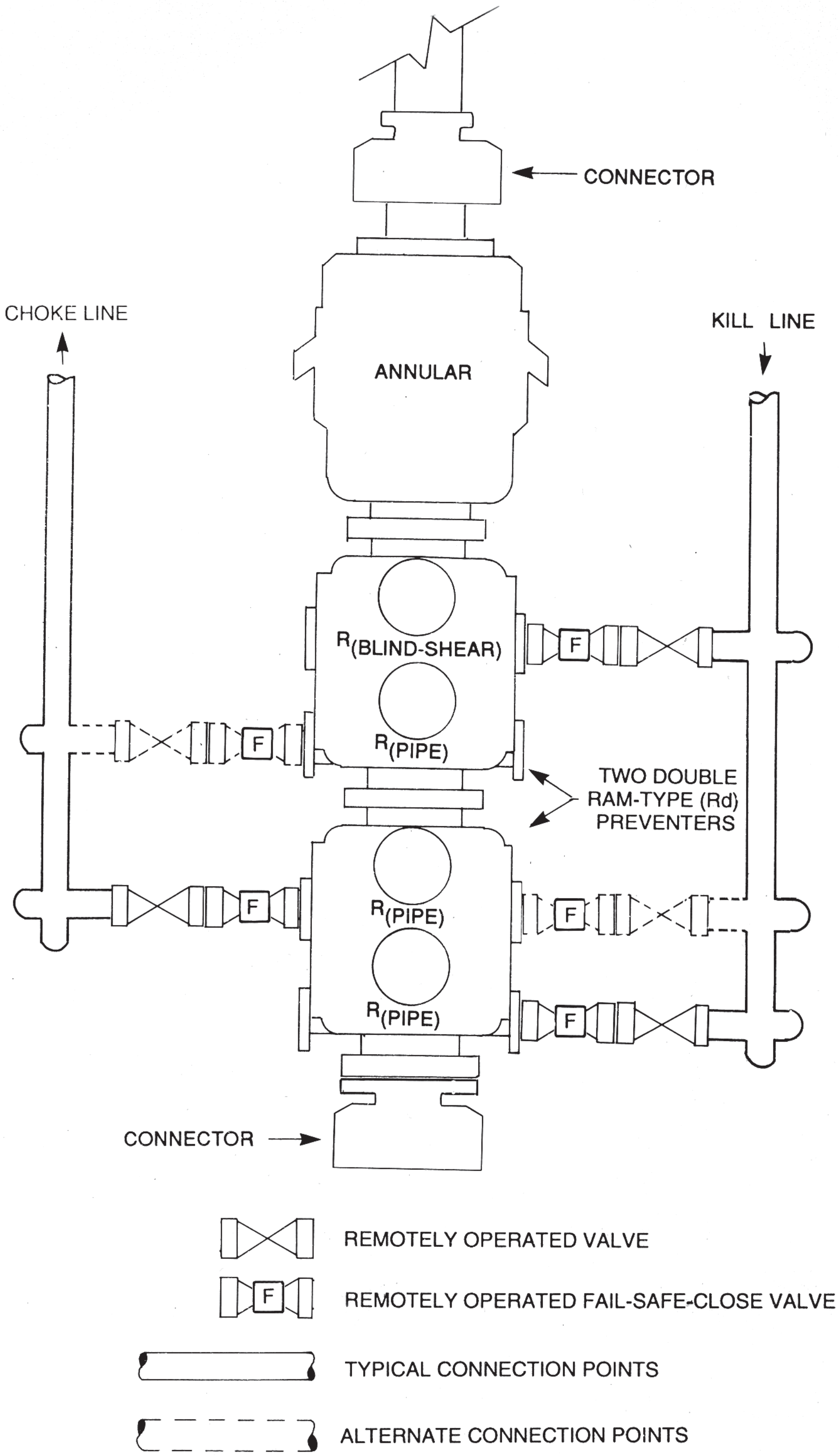
4. All right-angle turns in the choke and kill lines must be made with targeted crosses, tees, or target-type angle valves. The piping between the outer (control) valve and the choke/kill line connectors or stab subs must be as straight as is practicable, with slight changes of direction in this piping made with bends in the pipe itself, instead of by inserting fittings.

5. A schedule should be established for pumping through the choke/kill lines and valves, as they are closed normally and may become plugged with cuttings and/or gel material if not flushed occasionally.



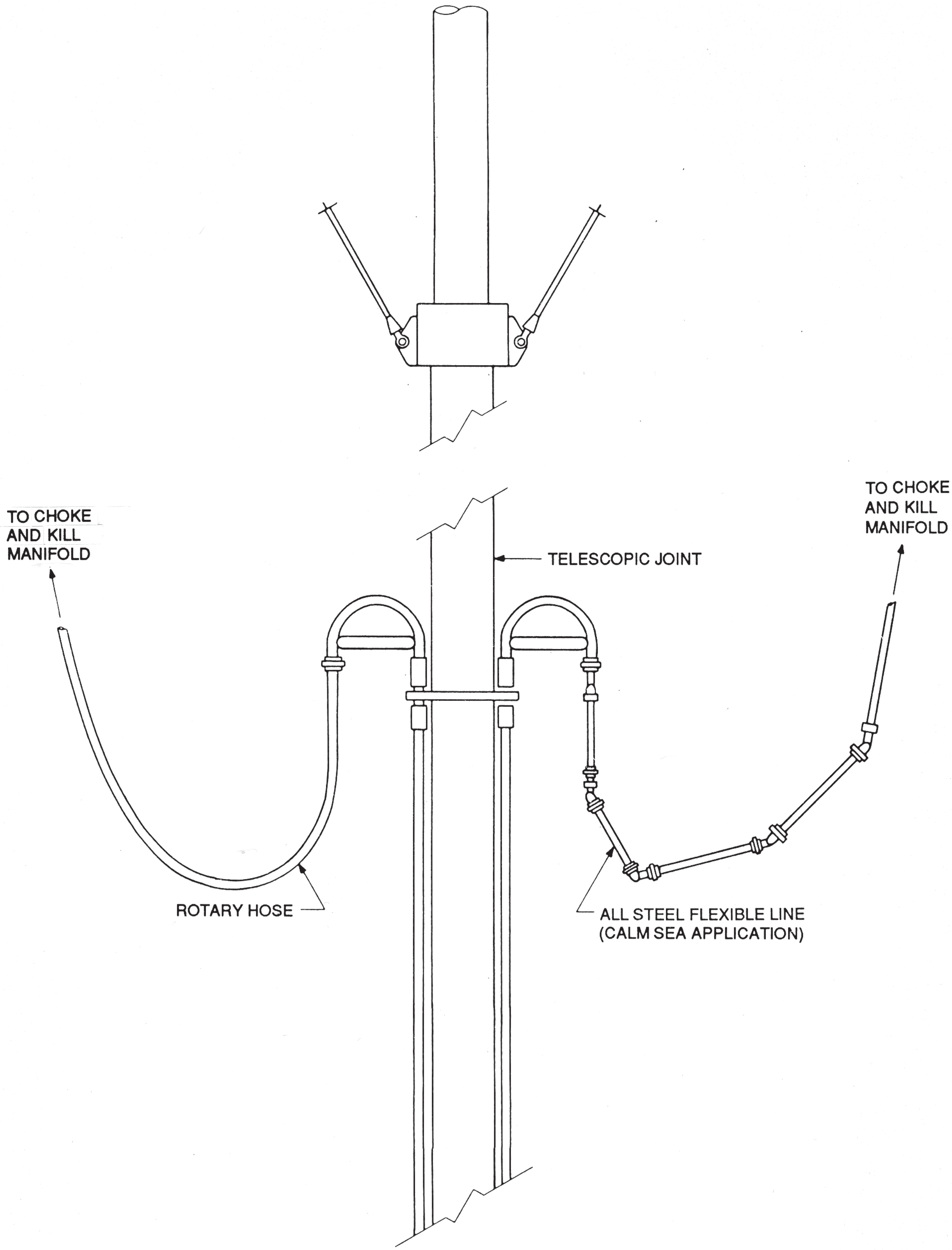
TYPICAL CHOKE AND KILL LINE CONFIGURATIONS FOR SUBSEA INSTALLATIONS

FIGURE 17



TYPICAL SUBSEA BLOWOUT PREVENTER STACK ILLUSTRATING CHOKE AND KILL LINE LOCATIONS

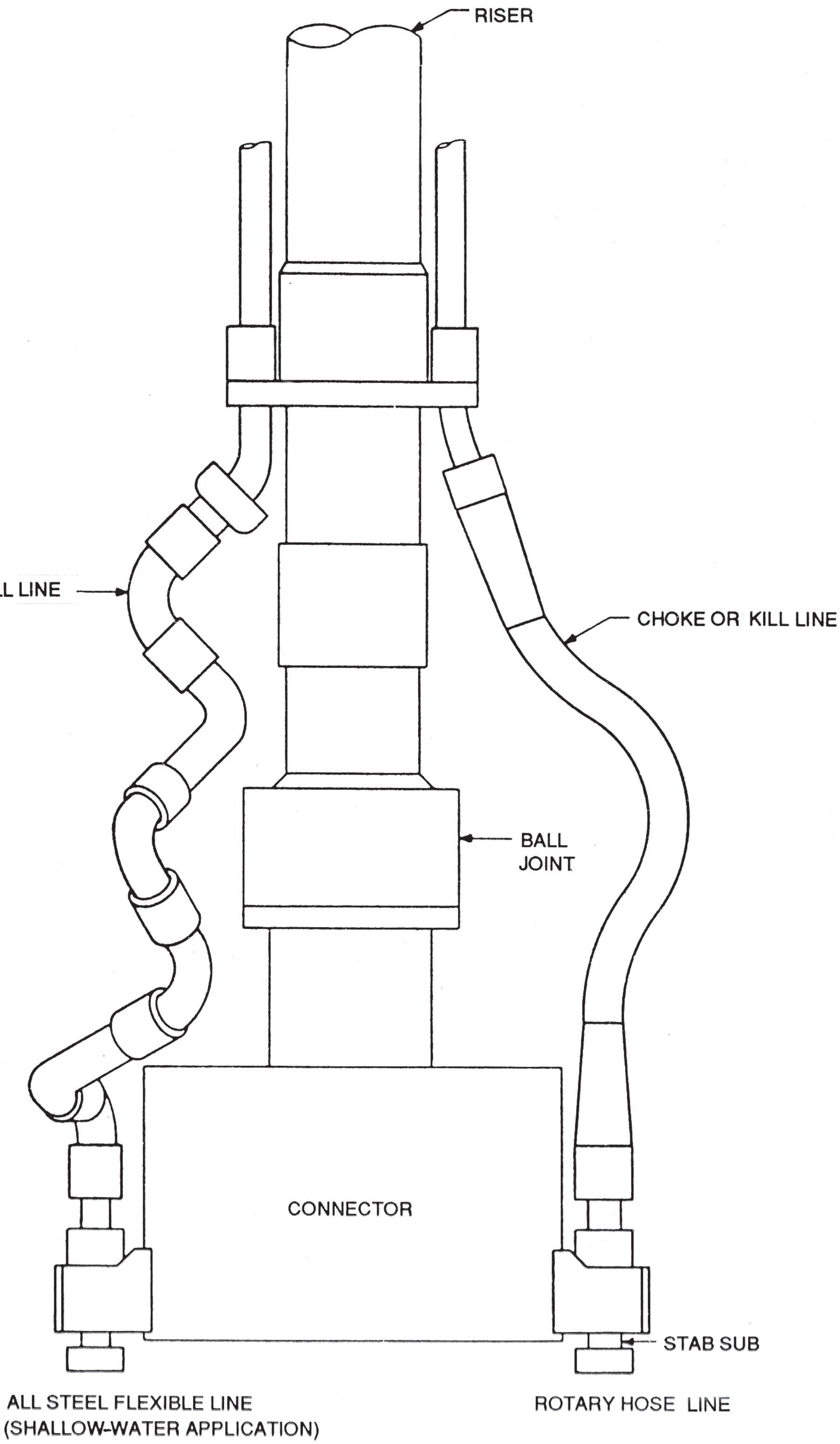
FIGURE 18



TYPICAL FLEXIBLE CONNECTIONS AT TOP OF MARINE RISER FOR CHOKE AND KILL LINES.

(CONFIGURATIONS FOR CALM AND ROUGH SEAS.)

FIGURE 19



TYPICAL FLEXIBLE CONNECTIONS AT BOTTOM OF MARINE RISER FOR CHOKE AND KILL LINES.
(CONFIGURATIONS FOR SHALLOW AND DEEPER WATER APPLICATIONS ILLUSTRATED.)
FIGURE 20

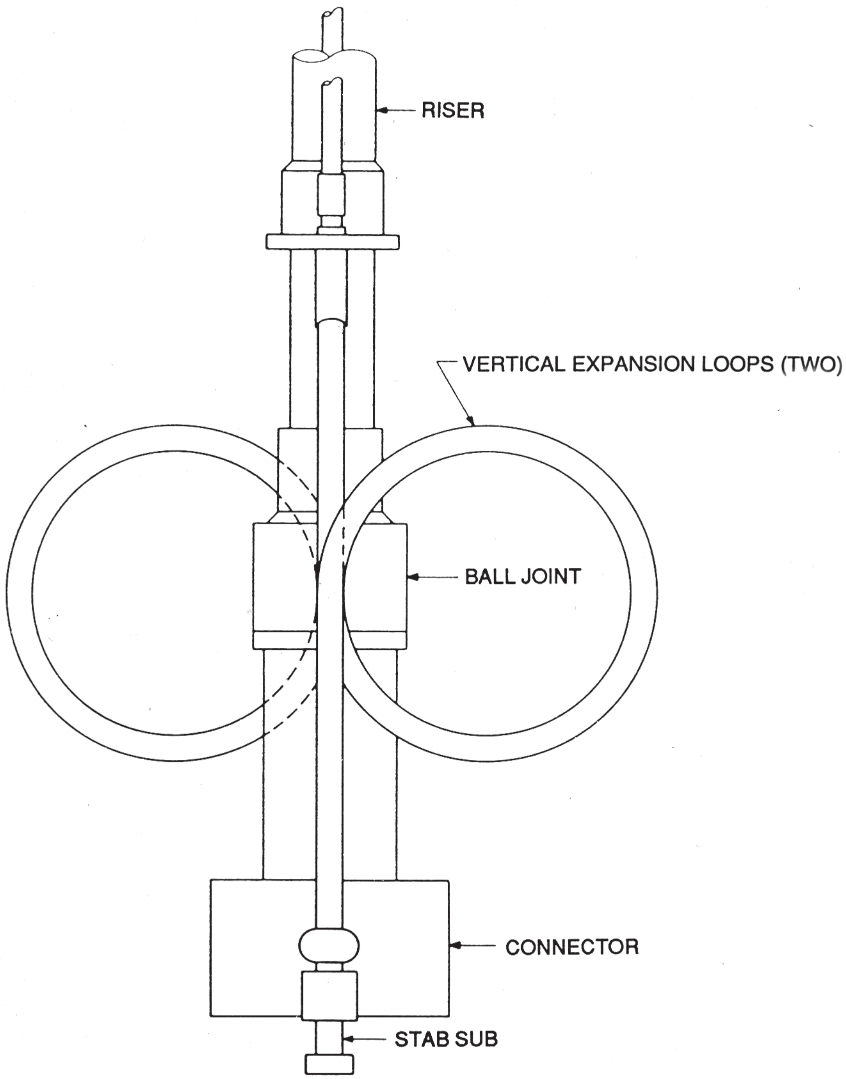


FIGURE 21

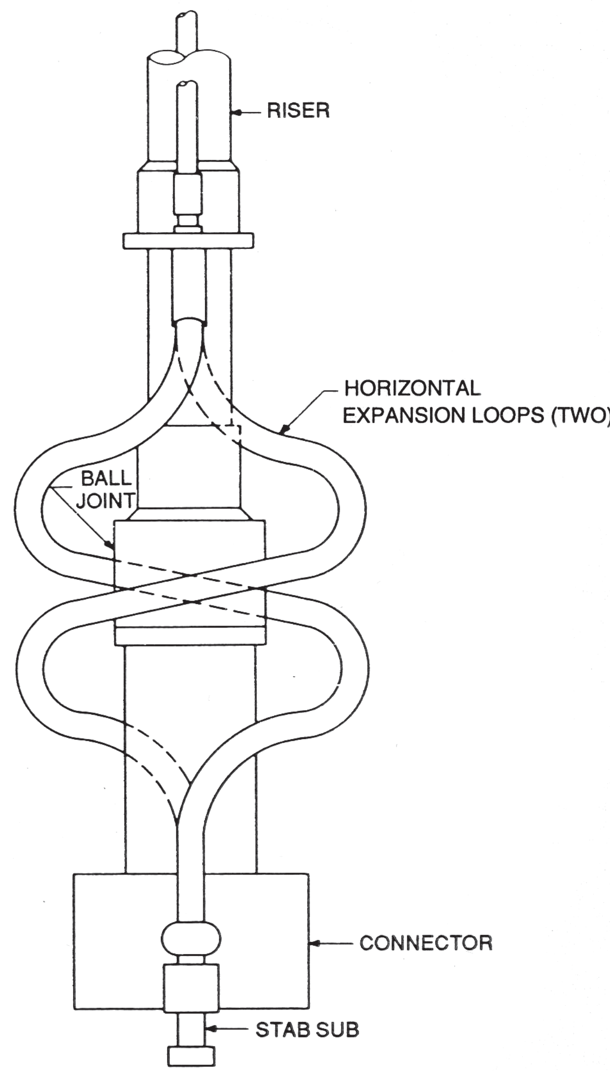


FIGURE 22

TYPICAL FLEXIBLE CONNECTIONS AT BOTTOM OF MARINE RISER FOR CHOKE AND KILL LINES.

c. **Installation Guidelines**. Some of the more important considerations concerning subsea choke and kill lines are:

1. Connector pressure sealing elements should be inspected, tested, and changed as required before being placed in service. Periodic pressure-testing is recommended during installation.

2. The pressure ratings of all lines and sealing elements must equal or exceed the rated working pressure of the ram preventers.

3. The selection of choke and kill line connectors must take into consideration the ease of connect/disconnect operations and the dependability of the sealing elements for those emergency situations where it is necessary to disconnect the lower marine riser package from the blowout preventer stack and then reconnect it before resuming normal operations.

4. The location of the choke and kill line connections on the blowout preventer stack depends on the particular configuration of preventers and the operator's preferred flexibility for well-control operations. Typical arrangements are shown in Fig. 18; however, other arrangements may be satisfactory.

5. The flexible connections required for choke and kill lines, both at the top and bottom of the marine riser, must have a pressure rating equal to or exceeding the rated working pressure of the ram preventers. Figs. 19 through 22 illustrate typical flexible connections for subsea installations.

6. The selection of the connections to the choke and kill lines at the top of the marine riser should take into consideration relative movement between vessel and riser, the environment, the type and temperature of fluids handled, pressure integrity, service life, ease of connect/disconnect operations, and replacement costs.

7. Bottom flexible connections (bypassing the ball joint) have the same requirements as the top connections, but are even more critical due to their relative inaccessibility and the environmental conditions under which they must operate. For deep water operations, particular consideration should be given to integrity and reliability in the presence of large pressure differentials.

3A-6 CHOKE MANIFOLD

a. **Variance from Surface Installations**. Fig. 23 illustrates a typical choke manifold for a subsea installation capable of handling 5M, 10M, and 15M working-pressure service. This assembly differs from a surface installation in that the choke and kill lines are manifolded to permit pumping or choking operations through either line. Other differences include the following:

1. There is at least one remotely controlled adjustable choke and several manually adjustable chokes positioned to permit back-pressure control through either the choke line or the kill line.

2. There is at least one valve in the exit line of each choke so the choke bodies may be pressure tested and each adjustable choke may be isolated from the buffer chamber, in case repair or replacement is needed.

3. The manifold is equipped with double valves immediately upstream of each choke and in the blowdown line.

4. An accurate pressure gauge is installed so the manifold (casing) pressure can be monitored.

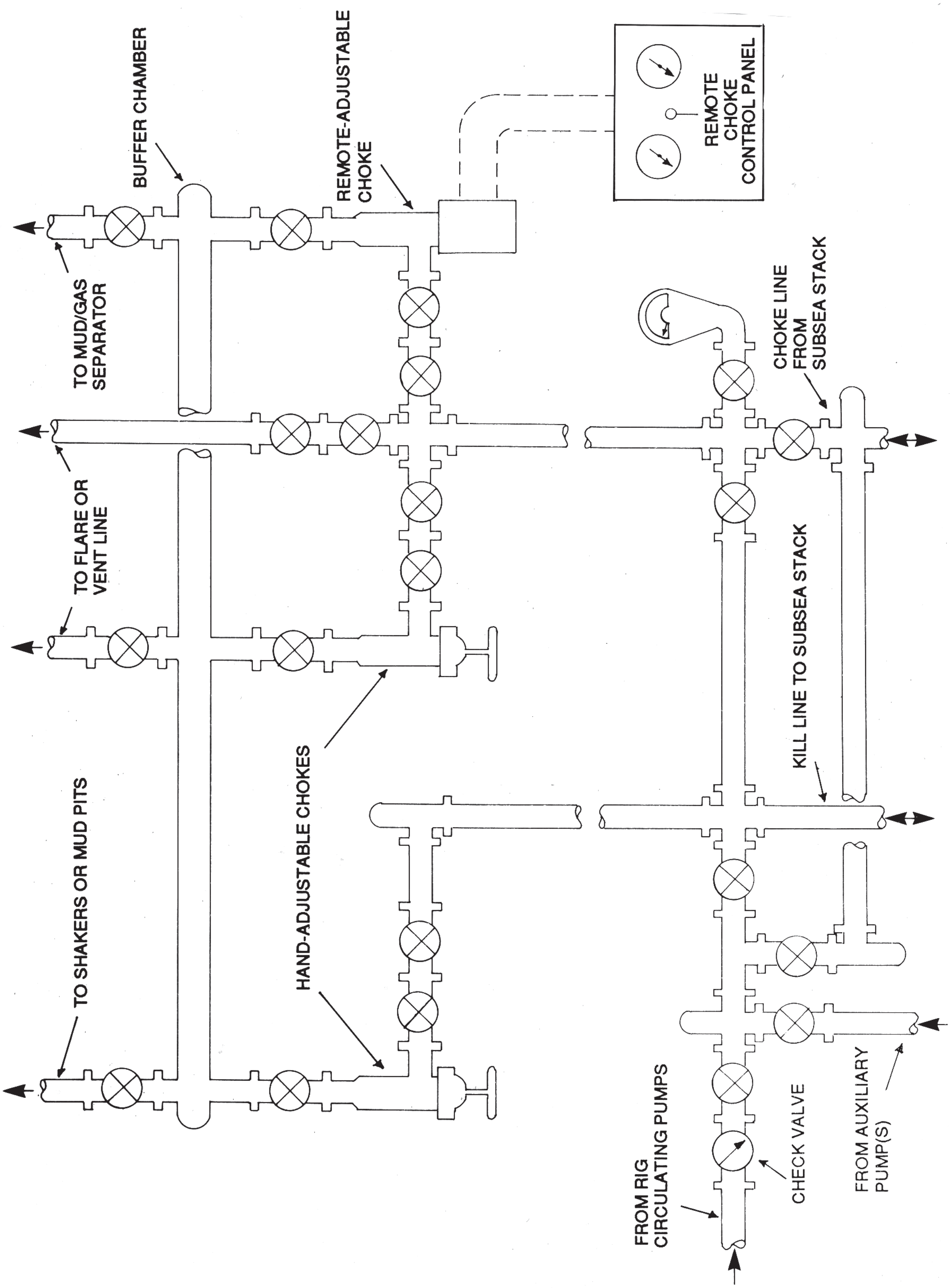
5. The manifold has tie-ins to the rig pump and to an auxiliary, high-pressure pump system.

b. **Installation Guidelines**. Division requirements for the planning and installation of choke manifolds for subsea installations include the following:

1. All components of the assembly (full-opening valves, fittings, piping, etc.) that are subject to well or pump pressure must have flanged, clamped, or welded connections and have a rated working pressure at least equal to the rated working pressure of the ram-type blowout preventers.

2. All components must be selected in accordance with applicable API specifications, taking into consideration pressures, volumes, temperatures, and conditions under which they may be operated (gas, oil, and/or drilling fluid service, hydrogen sulfide, environmental conditions, etc.).

3. The main header and the blowdown line must be 3-inch nominal diameter, or larger. All other components should be 2-inch nominal



TYPICAL CHOKE & KILL MANIFOLD ASSEMBLY - SUBSEA INSTALLATION.

FIGURE 23

diameter, or larger. The assembly should have the least practicable number of turns, and must be anchored securely. Turns in the assembly must be targeted, with the target opposite the line through which fluid will enter the turn during blowout flow. Dual choke/kill usage must be considered when selecting the orientation of the targets.

4. The choke control station, whether it is at the manifold, itself, or on the rig floor, must be as convenient as practicable and include all monitoring devices necessary to furnish an overview of the well control situation. The ability to monitor and control such items as standpipe pressure, casing pressure, pump-stroke rate and count, etc. from one location greatly increases well-control efficiency.

5. The rig air supply must be checked to ensure that it is adequate to provide the necessary pressure and volume requirements for controls and chokes. The remotely operated choke should be equipped with an emergency backup system, such as a manual pump or nitrogen, for use in the event that rig air becomes unavailable.

6. Initial testing of the entire choke-manifold assembly to the rated working pressure of the preventers should be performed when the blowout preventer stack is on the test stump (prior to running subsea). Although the body of each adjustable choke must be pressure-tested by closing a downstream valve, the actual choking mechanism (needle-and-seat, gate-and-seat, or orifice plates) does not have to be pressure-tested in the fully-closed position. Subsequent pressure tests of the choke manifold assembly should be conducted when the blowout preventers are tested subsea. The subsea tests should be limited to 70 percent of the rated working pressure of the preventer stack or the maximum anticipated surface pressure, whichever is greater.

7. Normally, lines downstream from the choke manifold are not required to contain the choke manifold's rated working pressure, but should be tested for integrity during the initial installation.

8. Lines downstream of the choke manifold must be anchored securely, be of sufficient size to minimize friction, and be manifolded to permit flow to a mud/gas separator, to the regular mud system, to production facilities or emergency storage, or to the trip tank for accurate fluid measurements during stripping operations.

9. Sometimes, buffer tanks are installed downstream from the chokes so lines can be manifolded together. When the buffer tanks are employed, provisions must be made to isolate a failure or malfunction without interrupting flow control. Also, any sharp turns must be targeted in the piping downstream of the chokes.

10. Adjustable chokes with a right-angle turn configuration must be installed so fluid passing through the choke exits the opening in line with the adjusting bonnet.

3A-7 AUXILIARY EQUIPMENT

a. **General.** The following auxiliary equipment must be provided and maintained in a state of operational readiness at all times. Any equipment that may be subjected to well pressures must have a working pressure rating at least equal to the rated working pressure of the ram preventers of the blowout preventer stack in use.

b. **Safety Valves**

1. A **kelly cock** must be installed between the swivel and the kelly stem, and a full-opening lower kelly valve must be installed below the kelly. If a downhole mud motor is to be used, kelly valves must be installed at the top and at the bottom of the joint of pipe used in lieu of the kelly. The lower kelly valve must have an outside diameter such that it can be run through the blowout preventers and the innermost casing string in the casinghead.

   If a top drive system is in use, one remotely operated kelly valve must be installed just below the drive mechanism.

   An operating handle to fit each kelly cock and valve must be maintained at a conspicuous location on the rig floor, readily accessible to the drilling crew.

2. A full-opening **drill pipe safety valve** must be available on the rig floor at all times and must be equipped to screw into any drill string member in use. (The lower kelly valve mentioned in 3A-7b1 may not be removed from the kelly during trips and used as a safety valve.) The safety valve must have an outside diameter such that it

may be run through the blowout preventers and the last casing string cemented in the well. The valve must be maintained in the open position and stored in a location or marked in a way that it **will be** the first valve installed in the drill string in the event that a kick is taken while tripping the working string.

A wrench to fit each valve must be maintained at a conspicuous location on the rig floor, readily accessible to the drilling crew.

3. An **internal blowout preventer** or drop-in pump-down check valve must be available on the rig floor unless a back-pressure (float) valve has been run in the drilling assembly. The inside preventer must be maintained in the open position and must be equipped to screw into any drill string member in use. If a surface-mounted inside preventer is used, it must be stored in a location or marked in a way that it **will not be** the first valve installed in the drill string in the event that a kick is taken while tripping the working string.

4. When running casing, a **casing safety valve** must be readily available on the rig floor and maintained in the open position. The valve must be equipped to clamp over a casing collar or screw into the casing string that is being run into the well.

c. **Wellhead Connector**. The wellhead connector is a hydraulically operated device that connects the blowout preventer package to the wellhead. The internal throughbore and rated working pressure of the connector must be at least equal to that of the ram-type preventers in the BOP stack in use. The connector must have some means of secondary hydraulic or manual release. Then, it can be unlocked if a malfunction occurs in the primary unlocking system.

The mechanical strength of the connector should be sufficient to withstand safely all the tensile, compressive, and bending loads to which it will be subjected during drilling operations.

The primary pressure seal must be provided by a metal-to-metal pressure-energized seal assembly.

d. **Marine Riser System**

1. **General**. A marine riser system is used to provide a flow path for fluid returns from the wellbore to either a floating drilling vessel (semisubmersible or hull-type) or a bottom-supported unit, and to guide the drill string and tools to the wellhead on the ocean floor. Components of this system include remotely operated connectors, flexible joints (ball joints), riser sections, telescopic joints, and tensioners.

Unless otherwise noted, the internal burst pressure-rating of the marine riser system (pipe, connectors, and flexible joint) must be at least equal to the rated working pressure of the diverter system plus the maximum difference between the hydrostatic pressure of the drilling fluid in the riser and that of sea water at the ocean floor. In deeper waters, collapse resistance may also be a consideration. Collapse could occur if circulation is lost, if the riser is voided of drilling fluid by a gas blow, or if the riser is disconnected from the lower marine riser package while full of drilling fluid.

In floating drilling operations, bypass valves located on the bottom of the riser may be employed to direct returns to the ocean floor when the formation competency at the setting depth of the conductor casing will not permit circulation of drilling fluids back up the riser to the vessel. These valves may also be used to flood the riser with sea water to aid in preventing collapse in the case of a riser that has been emptied for any reason.

2. **Marine Riser System Components**

a) ***Remotely Operated Connector***. An hydraulically actuated, remotely operated connector connects the lower marine riser package to the blowout preventer stack. It can be used as an emergency disconnect from the preventer stack, should conditions warrant.

The drift diameter of the connector must be at least equal to the throughbore of the blowout preventer stack, and its pressure rating must be equal to that of the other components of the riser system (connectors, flexible joints, etc.). When the operator wants to be able to install additional preventers on top of the original preventer stack, the rated working pressure of the connector must equal that of the ram preventers in the BOP stack. Connectors with the lower pressure rating are designated C_L, while those rated at the preventer-stack working pressure are designated C_H.

Additional factors to be considered in the selection of a proper connector should include ease and reliability of engagement and disengagement, ability to function in spite of angular misalignments, and overall mechanical strength.

b) ***Marine Riser Flexible Joint (Ball Joint)***. Flexible joints are used in the marine riser system to minimize bending, stress concentrations, and problems of misalignment in the rest of the system. Normally, the angular range of a flexible joint is 10 degrees from vertical. A flexible joint is always installed at the bottom of the riser pipe, either immediately above the connector used to join the riser to the blowout preventer stack or above the annular preventer when that preventer is located in the lower marine riser package.

For those vessels having a diverter system, a second flexible joint may be installed between the telescopic joint and the diverter to obtain the required flexibility. As an alternative to the ball joint, some type of gimballed mounting may be used. For deep-water operations or unusually severe sea conditions, a third flexible joint may be installed immediately below the telescopic joint.

For continuous drilling operations, the flexible joint should be maintained as straight as possible, normally at an angle of less than 3 degrees. Greater angles cause undue wear or damage to the drill string, riser, blowout preventers, wellhead, or casing. Some subsea BOPE arrays are equipped with a tilt-azimuth indicator on the flexible joint to provide a remote indication of the amount of joint deflection.

c) ***Marine Riser Sections (Joints)***: Specifications for riser pipe depend upon service conditions and a wide variety of environmental conditions during the riser's service life. The minimum yield strength and other fatigue characteristics of the selected riser system should exceed those required under reasonably anticipated future conditions.

The internal diameter of the riser pipe is determined by the size of the blowout preventer stack and the wellhead, with clearances allowed for running drilling assemblies, casing and accessories, hangers, annular preventer packing elements, wear bushings, etc.

d) ***Marine Riser Telescopic Joint (Slip Joint)***. The telescopic joint that serves as a connection between the marine riser and the drilling vessel compensates principally for the heave of the vessel. It consists of two main sections: the outer barrel (lower member) and the inner barrel (upper member).

The outer barrel is connected to the top of the riser pipe and remains fixed with respect to the ocean floor. It is equipped with attachments for connection to the riser-tensioning system and with connections for the choke and kill lines. One or more pneumatically or hydraulically actuated packing elements are contained in the upper portion of the outer barrel to provide a seal against the outside diameter of the inner barrel.

The inner barrel, which reciprocates within the outer barrel with the motions of the drilling vessel, has an internal diameter compatible with other components of the marine riser system. The top end of the inner barrel is attached to the drilling vessel below the rig substructure and has either a drilling-fluid return line or diverter system attached.

The telescopic joint should be capable of supporting anticipated dynamic loads while running or pulling the blowout preventer stack in either the extended or contracted position. It should also have a design strength adequate to resist stresses that might reasonably be anticipated during operations, and the stroke length with a safety margin that will accommodate the maximum established operating limits of vessel heave due to wave and tidal action.

e) ***Fill-up Line***. A fill-up line must be connected to the bell nipple at the top of the marine riser on subsea installations.

f) ***Tensioners***. The marine riser tensioning system that is attached to the outer barrel of the telescoping joint is designed to maintain the required amount of tension on the marine riser while, at the same time, compensating for vessel movement. The system consists of the following major components:

1) Tensioner cylinders and sheave assembly.

2) Hydropneumatic accumulator(s).

3) Power air-pressure vessels (APV).

4) Control panel and manifolding.

5) High-pressure air-compressor units.

6) Standby air-pressure vessels.

Maintaining adequate and near-constant tension on the marine riser is an important consideration in any operation involving a subsea BOP stack. Tensioning reduces bending stress and the concurrent probability of buckling, while minimizing the bottom ball-joint angle. On the other hand, increasing tension causes more axial stress in the riser; therefore, an optimum tension exists for a specific set of operating conditions (water depth, current, riser weight, drilling fluid weight, vessel offset, etc.). Minor overtensioning of the riser is less damaging than undertensioning.

The number of tensioners required for a specific operation will depend on such factors as riser size and length, presence or absence of flotation devices, drilling fluid density, weight of suspended pipe inside the riser, ocean current, vessel offset, wave height and period, and vessel motion. Periodic examination of riser tensioning system units should be made while in service, since the system can cycle as many as 6,000 times a day.

g) ***Riser Buoyancy Devices***. When drilling in deep water, it may be impractical to install enough tensioning units to provide adequate support for the riser. In these cases, some type of buoyant system may be necessary, such as syntactic foam flotation jackets, buoyancy tanks, etc. Although buoyancy devices reduce the requirement for tensioners, some of the advantage is lost as a result of the increased riser diameter, which exposes a greater cross-sectional area to wave forces and ocean currents. Therefore, special attention must be paid to the lower ball joint angle, and may require the installation of remote-reading, riser vertical-angle indicators and/or hole-position indicators.

e. **Guide Structure**. A four-post structure attached to the blowout preventer assembly on guideline-positioned subsea BOP stacks is the primary means for guiding the blowout preventer array onto the permanent guide base. Sec 13.3, API Spec 6A, *API Specification for Wellhead Equipment*, lists the standardized dimensions for the permanent guide base.

The upper section of the guide structure also provides guidance for the lower marine riser package. The guide structure, itself, may serve as a mounting base for some of the components of the remote control system and the choke/kill connectors or stab subs, and act as a frame to protect the blowout preventer stack from damage during handling operations.

f. **Guideline System**. A system of four cables (5/8-inch or 3/4-inch outside diameter) attached to the bottom of the posts on the temporary guide base and at the top of the tensioners on the vessel, guides the blowout preventer stack, marine riser, video equipment, and various other components into position on the ocean floor. Proper tensioning of this system is important, particularly during installation of subsea equipment. Because tensioning becomes more difficult as water depth increases, sonar- and video-positioned systems have been designed for use in deeper-water installations when guideline systems are not used.

3A-8 INSPECTION AND MAINTENANCE OF SUBSEA BLOWOUT PREVENTION EQUIPMENT

All subsea blowout prevention equipment must be inspected and maintained in accordance with the manufacturer's recommended procedures. All systems must be inspected visually at least once each day when weather and sea conditions permit. Subsea blowout-preventer and riser systems may be inspected by divers or with video equipment. Any necessary equipment repair or replacement must be accomplished without delay; however, full consideration must be given to well safety before starting any work.

A division inspector must witness the pressure testing of the blowout prevention equipment and related well-control equipment when the equipment is installed initially on the conductor casing of a well, and after each subsequent casing string is set.

All blowout prevention equipment tests must be recorded in the driller's log.

See Section 5-4 for additional inspection and testing procedures.

4. GEOTHERMAL EQUIPMENT DESCRIPTIONS, OPERATING CHARACTERISTICS, AND REQUIREMENTS

4-1 GENERAL

Blowout prevention equipment requirements for geothermal wells differ from well to well, depending on the type of geothermal environment being drilled, and differ in many ways from the requirements for oil and gas wells.

In general, surface pressures are quite low in high-temperature geothermal wells, thereby reducing the requirements for high-pressure BOPE frequently needed for oil and gas wells. On the other hand, geothermal flow rates are often quite high, necessitating larger choke, vent, and flow lines than normally needed for oil and gas wells with a low-pressure BOPE determination. In addition, special equipment, such as a banjo box, is used by the geothermal industry to deal with the unique drilling conditions encountered in a steam-dominated environment.

This chapter provides guidance when the drilling environment and the downhole characteristics of the rock and reservoir are known with a fair degree of certainty. However, when a high-temperature geothermal well is drilled in a wildcat area, or when a particular geothermal well situation is not addressed in this section, the BOPE should essentially conform to the requirements for an oil and gas well. Once the characteristics of the reservoir are determined, the requirements may be modified by the division.

Minimal guidance is provided for BOPE on low-temperature wells. Most low-temperature wells are similar to water wells. If additional questions arise for equipping and drilling low-temperature wells, refer to water-well industry drilling standards maintained in each division district office.

4-2 GEOTHERMAL ENVIRONMENTS

a. **Hot Dry Rock.** A hot dry rock environment is a high-temperature subsurface environment with little or no producible steam or water. Therefore, there is little or no chance of a blowout except from flashing by liquids used in the circulating system. Should a blowout occur, it would be of short duration. Nevertheless, BOPE similar to that used in a high-temperature hydrothermal environment is required because unanticipated pockets of fluid might be encountered.

b. **Hydrothermal**. A hydrothermal environment is a high- or low-temperature subsurface environment containing reservoirs of producible steam or hot water.

1. ***Steam-dominated reservoirs***. A reservoir in which the fluids are producible as saturated or superheated steam. Steam-dominated reservoirs present conditions that are very different from those encountered in oil and gas reservoirs; subsequently, there are many differences in the drilling methods and BOPE requirements. Typically, a well is drilled with mud as the circulating fluid to a point above the first anticipated steam entry. Then, the remainder of the well is drilled with air. Drilling conditions are then underbalanced and are similar to those encountered when drilling with a controlled flow, since there is no drilling mud to provide either blowout protection or the usual warning signs of a kick.

2. ***High-temperature water-dominated reservoirs***. A reservoir in which the temperature of the producible water is higher than the boiling point of water at local atmospheric pressure. Formation fluids can be produced as water or water and steam, depending on the back pressure maintained on the fluid. Because the water entering the well bore from the formation is in the liquid phase at least part of the time, the conditions are very similar to those encountered when drilling through high-pressure, gas-saturated oil zones or CO_2-saturated water zones in oil and gas fields, and the requirements for BOPE are similar. However, precautions are necessary because some of the hot reservoir water may flash to steam while being circulated out of the well.

3. ***Low-temperature water-dominated reservoirs.*** A reservoir in which the temperature of the producible geothermal water is lower than the boiling point of water at local atmospheric pressure. In many cases, drilling conditions are very similar to those encountered in oil and gas drilling, and the requirements for BOPE are similar. In other cases, conditions are similar to those encountered in water-well drilling, and pressure control techniques developed in the water-well industry may be adequate.

4-3 BOPE DESCRIPTIONS AND REQUIREMENTS

a. **High-temperature Reservoirs**

1. ***General***

a) Elastomer components (e. g. preventer packing elements, ram seals, etc.) must be made of a material formulated specifically to tolerate a steam or hot-water environment.

b) Some operators prefer to install all-steel rams in ram-type preventers placed immediately below or above the banjo box, instead of normal ram assemblies that are equipped with elastomer seals. This is allowed by the division.

c) Pressure-control equipment must conform to the provisions of Section 3 of this manual.

d) The equipment requirements outlined in this section are mandatory for most wells drilled into high-temperature reservoirs, either vapor-dominated or liquid-dominated, but exceptions may be made on a well-by-well basis, depending on well and geological conditions.

2. ***Descriptions of Components Unique to Geothermal BOP Stacks* (*see* Figure 24).** BOP stacks used for wells drilled with air in a high-temperature, hydrothermal reservoir include some or all of the following devices not commonly used in oil- and gas-well drilling:

a) **Slab Gate**. An optional, hydraulically operated, single-gate blind ram that is mounted above the permanent wellhead equipment and serves as the lowest element in the BOP stack. Because a slab gate must be able to function satisfactorily over a wide range of temperatures, the close tolerances and elastomer seal-surfaces found in normal ram-type preventers cannot be used and a complete seal is not expected from the slab gate. This valve is used as a working valve when the drill string is out of the hole.

If used, the slab gate is installed above the manually operated, gate-type control valve that is a component of the permanent completion system. The manually operated control valve is capable of a complete seal.

b) **Banjo Box**. A tee or box with a side outlet that redirects the flow of vapors, liquids, and drilled solids from the well bore to the blooie line. Frequently, the banjo box has a large chamber that will dissipate some energy of the steam or other vapors from the well bore.

c) **Blooie Line**. A large-diameter line that transfers the flow of well fluids from the banjo box to the muffler and separator when drilling with air. If portions of the hole are being drilled with mud or water as a circulating fluid, the blooie line may be closed off with a blanking plate or gate valve at the outlet from the banjo box, thereby directing the circulating fluid to the flow-line outlet of the rotating head [*see* f) in this section]. If a gate valve is used, a provision must be made for a secure platform or other means of ensuring the safety of anyone attempting to operate it. (The division does not regulate the selection and arrangement of components of the blooie-line system downstream from the control valve or blanking plate.)

The blooie line should have as few turns as practicable, and may have multiple ports that are used to inject liquids into the air-steam flow. The liquids help in removing drill cuttings and for hydrogen-sulfide abatement, if necessary. The choke line and/or blowdown line may also be vented into the blooie line through one of the ports.

Except for the fact that it operates full-time, the blooie line, together with the muffler and separator [*see* d) and e) in this section], perform the same function as the diverter system used in oil- and gas-well drilling.

d) **Muffler**. A larger-diameter section of the blooie line that reduces the noise of the expelled vapors.

e) **Separator**. A vertical, cyclone-type device at the end of the blooie-line/muffler system that separates the cuttings and liquids from the vapors. The vapors escape to the atmosphere from the top of the muffler and the cuttings and liquids are expelled from the bottom. The separator is similar to the mud-gas separator common in oil- and gas-well drilling operations.

f) **Rotating Head**. A device consisting of an outer housing that is flanged to the uppermost preventer and an inner, bearing-mounted stripper/packer assembly that rotates with the kelly. During normal air-drilling operations, the packer acts as a seal against flowing pressures to keep air, steam, and cuttings away from the rig floor. Normally, the rotating head must be cooled to protect the elastomer seals.

3. ***Equipment Requirements***

a) ***When Using Air as a Circulating Fluid (Equipment Classification HA)***. During the periods when air is used as the circulating fluid in a well being drilled into a high-temperature reservoir, the well must be equipped with the following (minimum) BOPE, listed from top to bottom (*see* Fig. 24):

1) A rotating head.

2) A double-ram (pipe and blind) blowout preventer or equivalent equipped with high temperature seals.

3) A banjo-box/blooie-line system, or approved substitute.

4) A full-closing gate-type control valve installed between the wellhead and the preventer/banjo box stack.

5) A kill line (2-inch minimum ID) with a check valve and at least one gate-, ball-, or plug-type control valve installed as close to the wellhead as is practicable.

6) A blowdown line (3-inch minimum ID) and at least two gate, ball, or plug valves installed as close to the wellhead as is practicable. The line must be anchored securely at all bends and as close to the exhaust outlet as is practicable. As an alternative to an anchored line leading away from the well bore, the blowdown line may be connected to one of the ports on the blooie line.

At the operator's option, the stack may be equipped with a slab gate and all-steel pipe rams between the required full-closing control valve and the banjo box.

Equivalent systems may be approved by the division.

b) ***When Using Mud or Water as a Circulating Fluid.*** Equipment requirements will vary depending upon which casing string is serving as the anchor string for the BOP stack and the type of fluid being used to circulate the cuttings out of the hole. Normally, wells drilled into water-dominated geothermal reservoirs are drilled with drilling mud; however, some may be drilled completely with air, while others are drilled partially with mud and partially with air for certain intervals.

1) ***Diverter System Requirements for the Conductor Casing (Equipment Classification HD)***. A diverter system is not designed to shut in or halt flow, but rather to route the flow to a safe distance away from the rig floor if a blowout occurs before deeper casing is cemented (*see* Section 2 for selection of equipment). Before drilling out the shoe of the conductor pipe, the division will require the following diverter-system equipment, unless the operator can demonstrate that such equipment is not needed.

The diverter system may be a combination of the following devices.

a. At least one diverter.

1. A rotating stripper head.

2. A remote-controlled, hydraulically operated annular preventer.

3. A substitute device approved in advance by the division.

b. A large-diameter vent line into the wellbore below the diverter. A 6-inch or larger ID line is recommended. The vent line may be attached to an outlet on the conductor casing, itself, or to a spool mounted between the conductor casing and the diverter. This line must be directed to a safe area.

c. A device in a vent line designed to prevent the flow of well fluids through the line during normal well operations, but able to permit flow in an emergency. This requirement may be satisfied by either of the following methods:

1. A riser installed in the vent line with an outlet above the level of the flow line. This would provide an open-flow diverter system (*see* Figure 13A).

2. A full-opening control valve, or rupture disk assembly, with a throughbore at least equal to the ID of the vent line, mounted in the line near the conductor casing. If a manual valve is used, it must be readily accessible and of an easy-opening design. If a remotely operated valve is used, it is suggested that the system be designed so the valve opens automatically as the diverter is closed. In a system where the diverter is an annular preventer, a remotely controlled, hydraulically operated valve may be installed so that the opening chamber of the valve is connected to the closing line of the annular preventer. Thus, the valve will be pressured open each time the preventer is closed.

2) ***BOPE Requirements for the Surface, Intermediate, and Production Casings (Equipment Classification HM)***. Before drilling out the shoe of the surface, intermediate, or production casing during mud or air drilling, installed blowout prevention equipment must include (at a minimum):

a. An annular preventer or a rotating head. If an annular preventer is used, it must be equipped with a hydropneumatic accumulator-actuating system.

b. A hydraulically operated, double-ram blowout preventer, or an approved substitute, with a minimum working-pressure rating that exceeds the maximum anticipated surface pressure (at the expected reservoir fluid temperature).

c. A kill line (2-inch minimum ID) equipped with a check valve and at least one control valve.

d. A choke line, or a blowdown line (3-inch minimum ID) equipped with at least two control valves placed as close to the wellhead as is practicable. The line should be anchored securely at all turns and at the end to prevent whipping or vibration damage during use. As an alternative to an anchored line leading away from the wellbore, the blowdown line may be attached to one of the ports on the blooie line.

The choke and kill lines may be installed on the side openings of the optional expansion spool, if one is installed, as part of the permanent-completion wellhead. Such a connection will be permitted only if the side openings of the expansion spool are large enough to accept the lines, and if it can be demonstrated to the satisfaction of the division that egress of fluids from the well bore will not be blocked by linear expansion of the inner string(s) of casing.

e. At the option of the operator, a full-closing gate-type control valve installed between the wellhead and the preventer/banjo-box stack.

f. A choke manifold will be required in the following cases:

1. When drilling an exploratory (prospect) well.

2. In those cases where gas is known to exist.

3. In those cases where abrasive wellbore fluids might be encountered.

The manifold must be equipped with at least one adjustable choke, a blowdown line (with an ID at least as large as the ID of the choke line), and an accurate pressure gauge. The choke should be of the multiple-orifice type or the cylindrical-gate-and-seat type. A remote-controlled choke is preferable to one that is controlled manually.

c) ***When Using Mud/Water and Air Intermittently as a Circulating Fluid (Equipment Classification HMA)*****.** In addition to the BOPE required in subparagraph b), the following additional equipment is required when a well is being drilled with air or another gaseous fluid:

1) A banjo box or approved substitute below the preventers.

2) A blooie-line/muffler/separator system.

3) A slab gate and/or ram-type preventer (equipped with all-steel CSO ram assemblies) may be installed between the banjo box and the full-closing control valve listed as optional in paragraph 4-3a3b)2)e.

d) ***Heat Exchanger or Mud Cooler****.* When the well is being drilled with mud as the circulating fluid, mud-cooling devices must be used when the temperature of the mud at the flow line is anticipated to be higher than the flash point for a continuous period of more than one hour.

4. ***Drilling Fluid Requirements****.* An adequate source of water or drilling mud and weight materials to ensure well control must be readily accessible at the drill site for use at all times.

b. **Low-temperature Reservoirs**. Following are the BOPE requirements for low-temperature and temperature-observation wells drilled in high heat-flow areas not previously drilled, or areas with a moderate- to high-potential for blowouts:

1. ***Equipment Classification LP*** (*see* Fig. 25):

a) An annular preventer and/or pipe- and blind-ram preventers.

b) A kill line and a blow-down line installed below the preventer.

2. ***Equipment Classification LD*** (*see* Fig. 26). In areas where geological conditions are known and where pressures are known to be at or below hydrostatic pressure, approval may be given for the use of a single diverter stack with a flow line installed below a blowout preventer, gate valve, rotating head, or approved (equivalent) device.

All required low-temperature BOPE equipment must be fully operational at all times. Pressure-control equipment must conform to provisions in Section 3 of this manual.

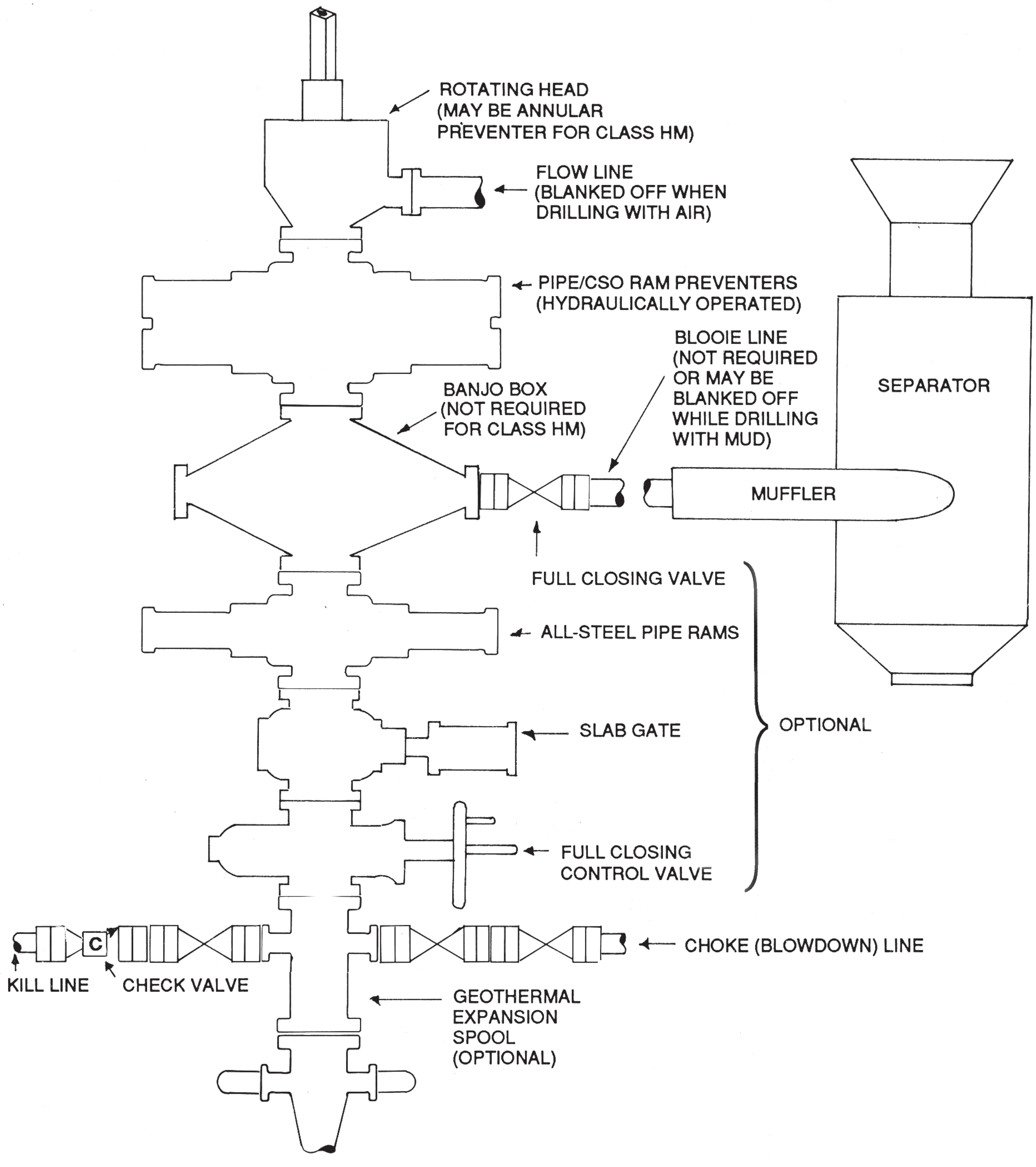
4-4 RELATED WELL-CONTROL EQUIPMENT (Auxiliary Equipment)

In addition to the requirements listed in Section 4-3, the following BOPE must be considered for all wells drilled in known or suspected geothermal resource areas.

a. A **full-opening safety valve** (sized to the working string in use) maintained in the open position on the rig floor at all times while drilling operations are being conducted, and when running casing. While tripping pipe during drilling operations, an operator may choose to make up the valve on the pin end of a joint of drill pipe that is kept readily available for stabbing into the working string. This procedure makes it unnecessary for the rig crew to pick up the valve and attempt to stab it by hand. Also, the hot fluids coming up the working string will be expelled above the crew rather than at the working level.

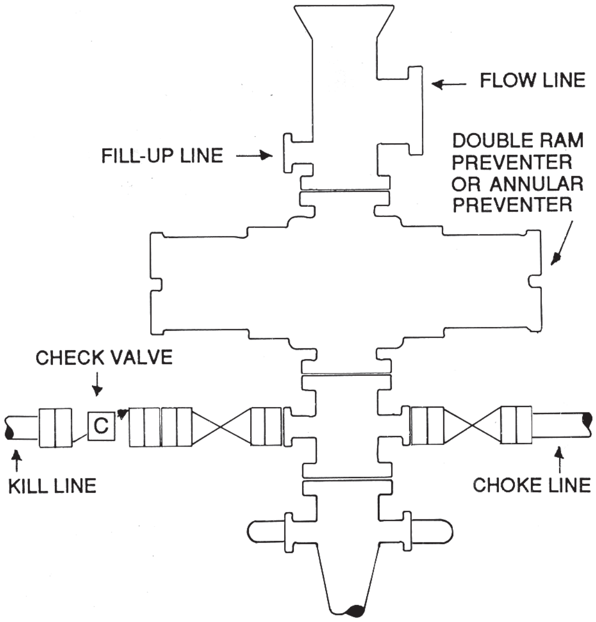
b. **An upper kelly cock** installed between the kelly and the swivel. If the uppermost item in the BOP stack is not a rotating head, a lower kelly cock may be used.

c. An **internal preventer** readily available to the rig crew, or a drill string float installed whenever the well is being drilled with mud or water as a circulating medium.

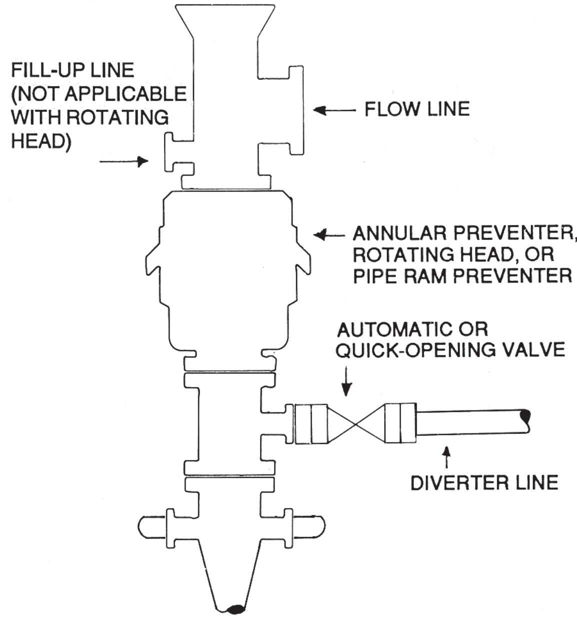


TYPICAL GEOTHERMAL BOPE STACK
HIGH-TEMPERATURE RESERVOIR
MUD/AIR DRILLING FLUID

(CLASS HMA)
FIGURE 24



TYPICAL GEOTHERMAL BOPE STACK
LOW-TEMPERATURE RESERVOIR PREVENTER SYSTEM
(CLASS LP)
FIGURE 25



TYPICAL GEOTHERMAL BOPE STACK
LOW-TEMPERATURE RESERVOIR DIVERTER SYSTEM
(CLASS LD)
FIGURE 26

4-5 BOPE TESTING, INSPECTION, TRAINING, AND MAINTENANCE

a. **Testing**. The annular and ram-type blowout preventers, the actuating system, and the auxiliary equipment must be tested in accordance with the provisions outlined in Section 5 of this manual; however, pressure-testing of any all-steel ram or gate is not required. When witnessing a pressure test of the BOPE, division engineers must ensure that the pressure inside the banjo box does not exceed the rating of the box, which usually does not exceed 200 psi.

b. **Inspection and Actuation**. All required BOPE must be inspected and, if applicable, actuated periodically to ensure operational readiness. The minimum frequency of this inspection/actuation is as follows:

1. Once each eight-hour tour, the following are to be performed:

    a) Check the accumulator pressure.

    b) Check the pressure of the emergency backup system.

    c) Check the hydraulic fluid level in the accumulator unit reservoir.

    d) Test all audible and visual indicators and alarms once each trip, but not less often than once a week.

2. Once each trip, but not more often than once every 24 hours, the following are to be actuated:

    a) Pipe rams (when off bottom, but before starting out of the hole).

    b) Blind (CSO) rams (after pulling the pipe from the hole).

    c) All kelly cocks.

    d) Drill pipe safety valve.

e) Hydraulic control valves (if any).

3. Once each seven days, the following are to be actuated:

   a) The annular preventer (if installed) on drill pipe or tubing.

   b) All gate valves in the choke and kill systems.

   c) The full-closing control valve on the wellhead, if installed.

   d) All manual locking devices on ram-type preventers.

   e) Internal preventer (if required) by loosening the dart valve setscrew and permitting the valve to close. Reset the dart valve so that the preventer is stored in the open position.

   f) Adjustable chokes (if required).

   Also, the flange bolts or studs at all preventer and wellhead connections must be tested for tightness every seven days.

c. **Crew Training**. BOPE practice drills and training sessions must be conducted at least once each week for each crew, and may be performed in conjunction with the operational-readiness tests outlined in paragraph 4-5b. Training must be such that each member of the crew has, at a minimum, the following:

   1. A clear understanding of the purpose and the method of operation of each preventer and all associated equipment.

   2. The ability to recognize the warning signs that accompany a well kick or steam blowout.

   3. A clear understanding of each crew member's station and duties in the event of a kick or steam blowout while drilling, tripping pipe, while drill collars are in the preventers, and while out of the hole.

d. **Records**. A record of all inspections, tests, crew drills, and training sessions must be kept in the daily log book.

e. **Maintenance**. All equipment must be maintained in accordance with the manufacturer's recommendations and/or the requirements of this manual.