1700 Wellhead Control Systems

Abstract

This section provides guidance for the design of a wellhead control system to be used to monitor the flowing conditions of the well flowline and to initiate a shutdown of the well. The various components of a wellhead shutdown system, their function in the system, and their operation are discussed. Shutdown systems for both surface controlled and subsurface controlled shutdown systems are included.

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1710 Basic Principles

The function of the wellhead control system is to monitor each well's flowline pressure, interface with the facility Emergency Shutdown System (ESD), and control the surface safety valve (SSV).

Like other shutdown systems described in Section 1300, a wellhead control system should be used to prevent the risk of injury or damage to personnel, the environment, or equipment. Wellhead control systems are designed to be "fail-safe."

When required, the wellhead control system also monitors the surface controlled subsurface safety valve (SCSSV) for the well. SCSSVs are required for offshore platforms. Regulations, such as API RP 14 C and the Minerals Management Service OCS Order No. 5, govern the requirements for these safety systems.

SCSSVs have been installed on land wells in some facilities that are located near population centers or where the wellhead may be subject to physical damage.

When hydraulically operated SCSSVs are required, the wellhead shutdown system must include a hydraulic reservoir and pump system to maintain pressure on the subsurface valves during normal operation.

Almost all wellhead control systems are pneumatic for sensing and control of the surface safety valve (SSV). Pneumatics have been widely used for a long time and are accepted by the users. Pneumatics work well in the vicinity of wellheads, where they are subject to vibrations and fluids from drilling activities.

On land, a separate wellhead control system is usually provided for wells operating under pressure flow conditions, when damage or injury to the environment, personnel, or equipment could occur.

In temperate climates the controls may be mounted individually out-of-doors. In colder climates the controls are often mounted in a small panel, which may be housed in a building or shelter.

On offshore platforms, the wellhead control systems are grouped on one or more panels. The control logic for each well is kept separate from the other wells so that wells may be easily added to or deleted as required. SCSSVs are hydraulically controlled and operated from these panels. A separate hydraulic system is usually furnished for every panel. Shutdown controls for each pneumatically operated SSV and its SCSSV are arranged together on the same control panel.

When instrument air is available, as it is on many offshore platforms, it is the best source of gas pressure to operate these safety control systems. When instrument air is not available, process gas can be used. The source of gas pressure for the control system must be dry and filtered and free of contaminants.

Nitrogen is often used on land as the source of gas pressure in the following circumstances:

- When only sour gas is available
- When hydrocarbons cannot be vented to the atmosphere

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- When a source of clean, dry gas is unavailable

In extreme cold conditions, hydraulics have been used for the surface control systems.

Electric Wellhead Control

Electrical control systems have been developed and are very feasible for harsh climates or when handling toxic fluids in the flowline.

One Company location in Wyoming, faced with an extremely high level of H_2S, has successfully used electric pressure switches, hand switches, and solenoid valves on every wellhead in the entire field for years. They also included H_2S detectors as one of the shutdown sensors.

When annunciation or indication of the shutdown sensor is important, electric shutdown systems would be more flexible, easier to implement, and more cost effective than pneumatic systems.

Electric systems are far easier to interface with a Supervisory Control And Data Acquisition (SCADA) system for remote monitoring and control.

1711 Shutdown Sensors

Generally, four types of shutdown sensors are used to send signals to each wellhead control panel:

- Process and ESD shutdown pilot relays
- Fusible plugs on fire loop systems
- High- and low-pressure sensors from the flowline
- Sand probes in the flowline

SSVs are closed by any of the above devices whether on land or offshore. SCSSVs are shut down only by an ESD or fire signal and only after a time delay to allow the SSV to close first.

Process Shutdown Relays

The pneumatic wellhead control system must be pressurized in order to operate. The interface with the process or platform shutdown system is accomplished by using a pilot relay. Pilot relay is short for a “pilot operated, three-way valve or relay.”

The relay consists of a three-way block and bleed valve and a pneumatic piston or a pressure pilot on the other end. The relay is mounted inside the wellhead control panel. This pilot relay will automatically reset when the process shutdown system has been repressured or brought back to a normal situation. With a signal applied from the remote process or platform shutdown system, the three-way pilot valve allows free passage of the pneumatic holding pressure. When the remote signal is removed, the relay will switch, block in the supply pressure, and vent all the downstream holding pressure. This series of actions will initiate a wellhead shutdown by venting the pneumatic signal from a manually reset pilot relay that controls the surface safety valve (SSV).

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Manual Reset Relays

A shutdown signal from a plant or platform ESD to the wellhead control system is usually caused by a possible dangerous or damaging condition existing downstream of the wellhead.

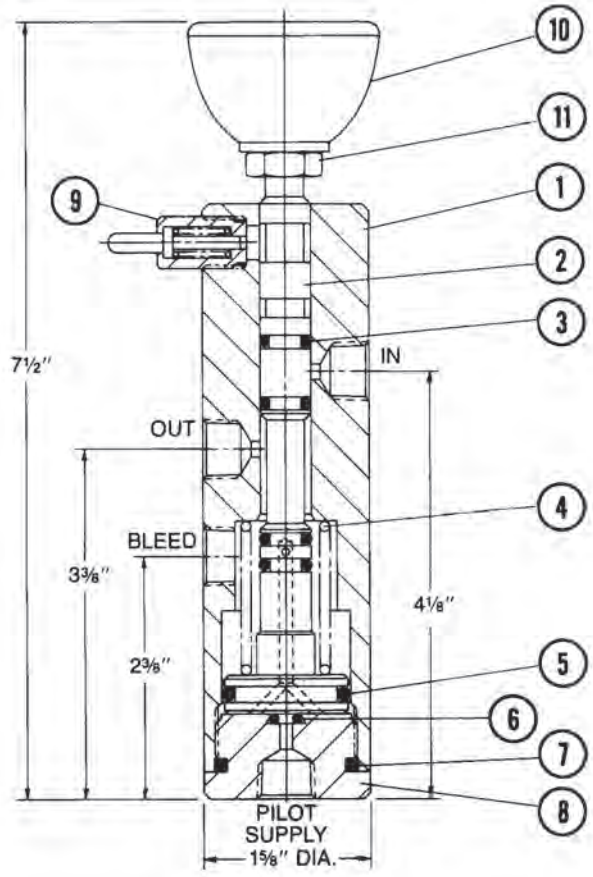
It is important that the wellhead shutdown system be designed with a manual reset pilot relay. See Figure 1700-1. The manual reset pilot relay has a knob on one end as well as the pressure pilot on the other end of a three-way valve. The three-way valve will switch and shut down the surface safety valve either when the knob is pushed or the pilot is depressured.

Fig. 1700-1 Pilot Relay with Manual Reset *(Courtesy of the Cooper Cameron Corporation, owner of the W-K-M trademark.)*

The Model 3300-A pilot relay valve is a normally closed, block and bleed three-way valve. The relay will stay locked in the normally closed position until the pull knob is pulled out. In this position, the spool valve is pinned with the automatic bypass holding the spool valve open, allowing actuator pressure to flow through. When instrument pressure is applied to the bottom of the relay piston, the spool valve is moved upward, automatically releasing the automatic bypass pin. As long as instrument pressure is present at the bottom of the relay piston, the relay will stay in operating position. Loss of instrument pressure returns the relay to its locked closed position and back-bleeds the downstream side. In the closed position, the relay is automatically locked closed and must then be manually reset for operation.

FEATURES:

1. Fail safe.
2. Automatic bypass pin release.
3. Internal lock-closed device.
4. Manual shut-in of SSV by pushing in pull knob.
5. Can control multiple wells individually.
6. Pressure through relay from 0 to 250 psi.
7. Instrument pressure from 30 to 40 psi.
8. Materials meet NACE MR-01-75 specifications.
9. Viton seals. (Temperature range -20°F +400°F.)
10. Can be panel-mounted. Hole size is 1.5 inches.
11. All ports 1/4" NPTF



This means that when the shutdown signal is initiated, the system will trip and stay shut down. Clearing of the possibly dangerous or damaging condition will not automatically reset the system and open the surface safety valve. The only way the SSV or the SCSSV can be opened is for the production operator to manually reset this shutdown relay by pulling the knob. Pulling the knob sets a pin that latches the

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three-way valve until pressure is applied to the pilot. The pin will disengage when the pilot is pressured, thus activating this shutdown relay.

This relay should not have a lockout feature that disengages the manual reset, which would allow the surface safety valve to automatically cycle shut and open. The design of this safety relay should require that it can only be latched in the open position while no instrument pressure is applied to the pilot diaphragm.

Indicators are available to enable the operator to tell at a distance that a wellhead surface safety valve is shut down. On panels controlling multiple wells, indicators for the valve signals are very helpful to the operator. These indicators can be integral to the relay knob, or they can be a separate panel-mounted device.

It is important to determine that the possibly dangerous or damaging condition has been corrected and to make sure that the operator is present at the wellhead to monitor the well while it is placed back into operation.

Pressure Sensors

High- and low-pressure sensors are used to monitor the flowline pressure of the well downstream of the choke. The high-pressure sensor is used to protect both the final flowline segment and the downstream process equipment. The low-pressure sensor is used to detect a leak or flowline rupture. Requirements for pressure sensors are covered in API RP 14C Section A1 for offshore platforms and by established Company practices.

The settings for these sensors must be carefully determined, reviewed, and documented. Because of the pressures normally encountered in flowline service and the proximity to the workover operations, the most commonly used pressure sensors are called “stick pilots.” See Figure 1700-2.

These pressure sensors come in a wide selection of ranges, which can be easily adjusted. The sensors have 1/2 NPT connections and are typically color-coded to identify the spring range. See Figure 1700-3.

The pressure sensors are usually connected in tandem. The holding circuit supply pressure is connected to the inlet of the high-pressure pilot. The low connection of the high-pressure pilot is connected to the inlet connection of the low-pressure pilot. The upper connection of the low-pressure pilot continues through the system holding circuit. A typical pneumatic hookup is shown in Figure 1700-4.

Should the flowline pressure downstream of the choke exceed the preset limit, the high-pressure sensor internal piston will shift upwards, blocking its supply port and venting the holding circuit pressure, thus triggering a wellhead shutdown. Should the flowline pressure decrease below the low limit, the low-pressure sensor internal piston will shift down, blocking its supply port and venting the holding circuit pressure, thus triggering a wellhead shutdown.

Pressure sensors are normally mounted on a manifold on the flowline and on the pneumatic signal tubing sent to the wellhead control panel. Some of the reasons for remote mounting are as follows.

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Fig. 1700-2 Typical Pressure Sensor *(Courtesy of the Cooper Cameron Corporation, owner of the W-K-M trademark.)*

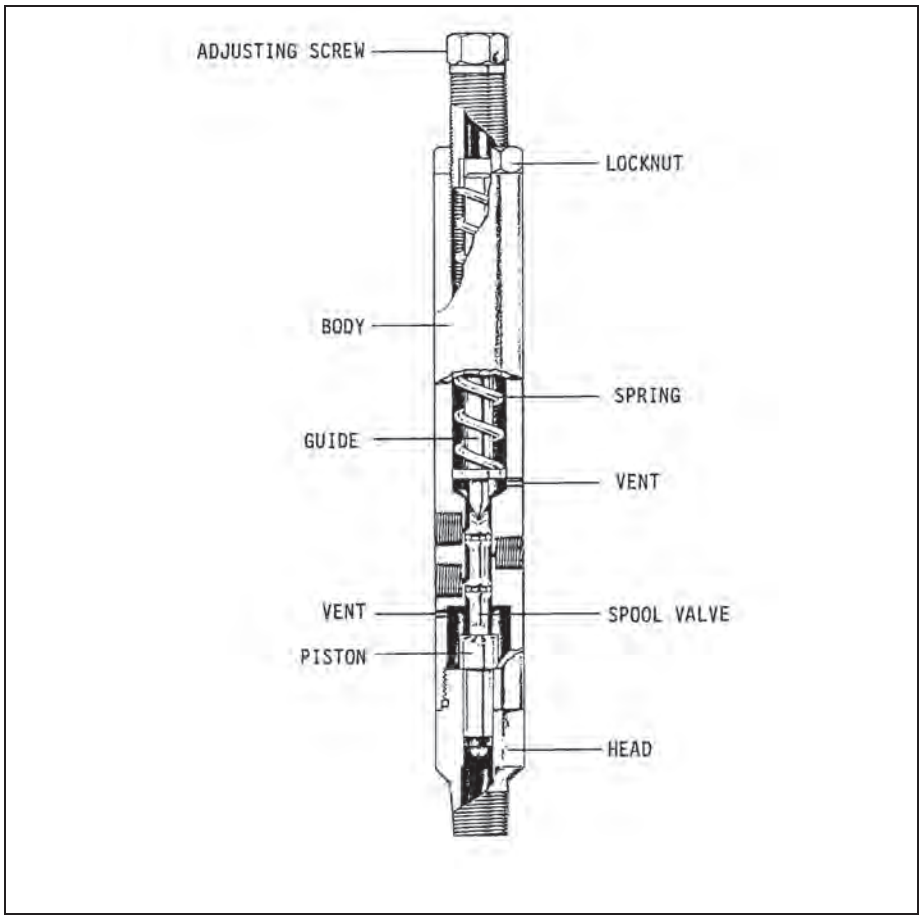


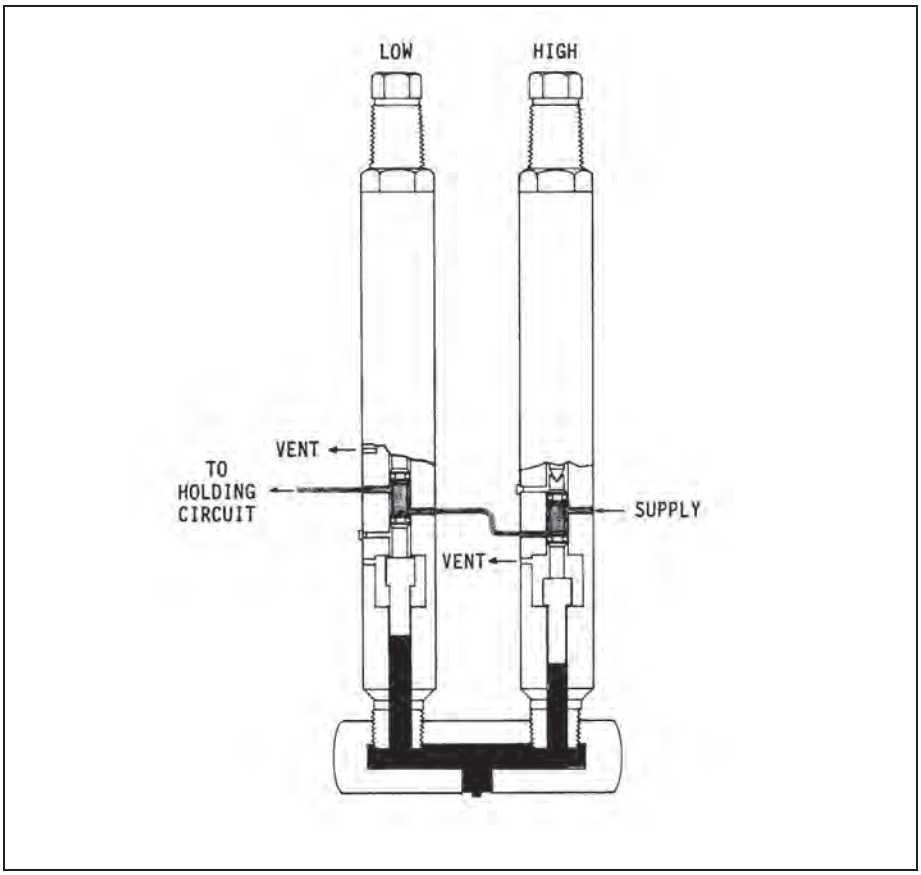
Fig. 1700-3 Typical Pressure Sensor Ranges *(Courtesy of the Cooper Cameron Corporation, owner of the W-K-M trademark.)*

Pressure Range:

Dash No.	Piston Size	Pressure Range Min.	Pressure Range Max.	Color Code	Approx. Rate Per Turn	Max WP, psig
−1	1½"	5	20	Plain	1	2,000
−2	1½"	20	60	Red	3	2,000
−3	1½"	50	110	White	6	2,000
−4	1½"	100	200	Blue	8	2,000
−5	⅞"	20	50	Plain	3	6,000
−6	⅞"	80	170	Red	8	6,000
−7	⅞"	150	400	White	25	6,000
−8	⅞"	400	600	Blue	50	6,000
−9	⅜"	500	1,000	Red	40	10,000
−10	⅜"	1,000	2,500	White	80	10,000
−11	⅜"	2,000	3,500	Blue	165	10,000
−12	¼"	3,000	6,000	White	275	10,000
−13	¼"	5,000	10,000	Blue	550	10,000

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Fig. 1700-4 Pressure Sensors in Tandem Service *(Courtesy of the Cooper Cameron Corporation, owner of the W-K-M trademark.)*



- To avoid high wellhead pressures and process fluids in the control panel
- To reliably measure viscous liquid hydrocarbon pressures by having the sensors mounted close to the process
- To minimize the risk of chloride or sulfide stress cracking when corrosive fluids are present
- To avoid plugging problems in the tubing when paraffins are present
- To avoid plugging problems in the tubing when the formation of hydrates is possible
- To avoid freezing in long process leads in cold environments
- To avoid mechanical damage during workover operations

Dual pressure pilot sensors, such as the Fisher Model 4660, have been directly mounted in the control panel in some locations.

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Sand Probes

Sand probes are used on flowlines where erosion due to flowing conditions may be experienced. Under these conditions the probe will erode with the passage of sand and actuate the sensor.

When properly placed in the flowline, the number of sand probe sensor failures can be valuable in helping to determine the erosion wear on the flowline. Therefore, the number and date of occurrence of sand probe failures should be carefully documented. One rule of thumb is to schedule for a wall thickness test (e.g., x-rays) after four sand probe failures.

Sand probes should be inserted in a straight run of pipe at least ten (10) feet downstream of the well choke or any other change in piping direction. The pipe downstream of the probe should also be straight for another four feet. Probes should be selected for the line size of the flowline and should be purchased with 1/2 NPT connections. Figure 1700-5 shows a typical sand probe sensor.

When erosion causes failure of the probe, the flowline pressure enters the sand probe sensor and the internal piston shifts upwards. The supply or instrument port is blocked, and the holding circuit pressure is vented, thus triggering a wellhead shutdown.

The manual handle of the sand probe will give an instant indication that the sand probe has tripped. This manual handle may also be used to manually test the wellhead control system.

1712 Fail-Safe Design

Two types of failure modes are described in Section 1300, "Process Alarm and Shutdown Systems." One mode is de-energized-to-trip and the other energized-to-trip. All wellhead control systems and components must use the de-energized-to-trip design, which means that the system will be a fail-safe design.

As previously mentioned, the fail-safe design is accomplished by maintaining a pneumatic pressure holding circuit on all the components of the control system located at the surface of the wellhead and a hydraulic pressure on the SCSSV during normal operation.

A typical simplified pneumatic circuit for a wellhead control of an SSV is shown in Figure 1700-6.

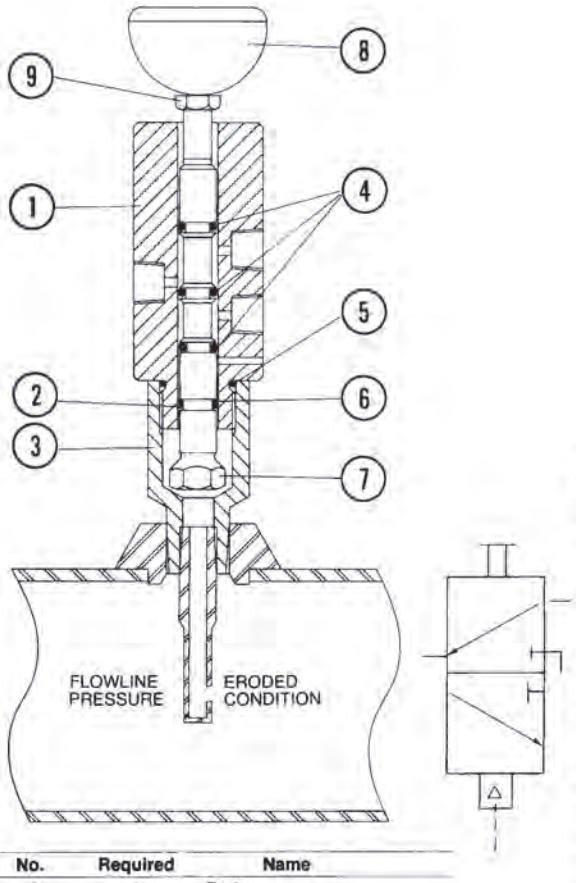
1713 Surface Safety Valve (SSV)

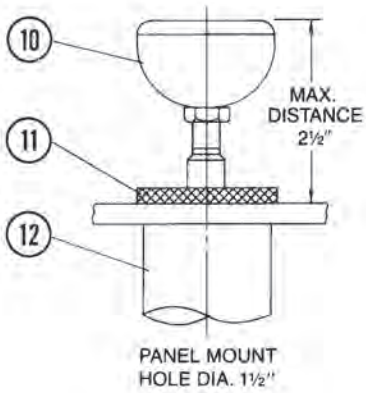
The SSV is normally located as a wing valve on a high- or low-pressure wellhead Christmas tree. This name is derived from the tree-like appearance of the valves and fittings branching out from it. A manual valve must be installed between the SSV and the well to allow for maintenance. See Figure 1700-7.

The type of valve used in the flowline for a shutdown valve is usually a reverse gate valve. This valve is well suited for this application due to its self-closing feature.

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Fig. 1700-5 Typical Sand Probe Sensor *(Courtesy of the Cooper Cameron Corporation, owner of the W-K-M trademark.)*





No.	Required	Name
1	1	Body
2	1	O-Ring
3	1	Head
4	3	O-Ring
5	1	O-Ring
6	1	Back-up Ring
7	1	Spool Valve Assembly
8	1	Pull Knob (Black)
9	1	Jam Nut
10	1	Pull Knob (Red)
11	1	Lock Ring
12	1	Body (Panel Mount)

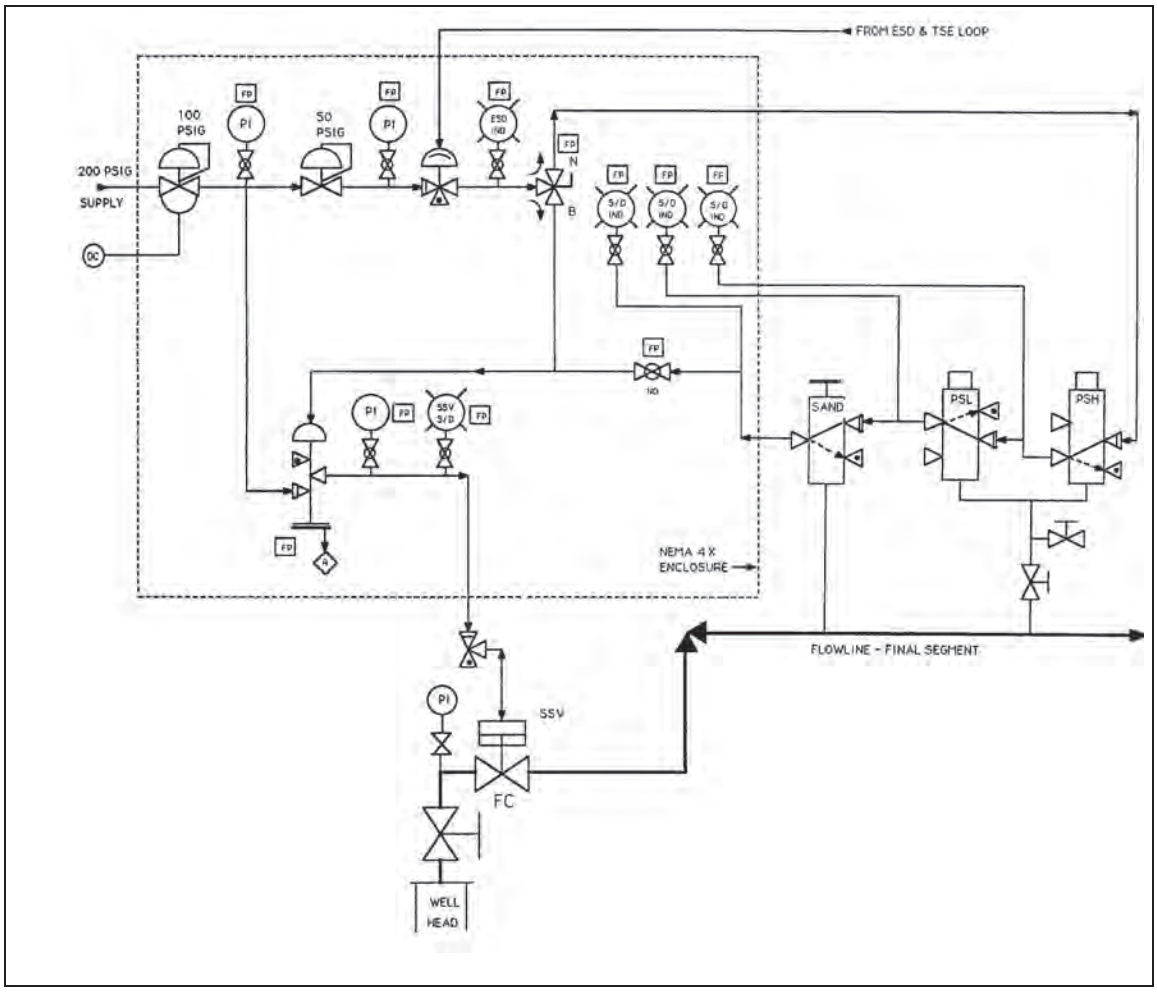
PROBE DATA

END CONNECTION	LINE SIZE	PRESSURE RATING, PSI	PROBE WALL THICKNESS
¼" NPT	2"	5,000	.035
¼" NPT	2"	8,000	.050
¼" NPT	2½"	5,000	.035
¼" NPT	2½"	8,000	.050
¼" NPT	3"	4,000	.035
¼" NPT	3"	6,000	.050
¼" NPT	4"	4,000	.035
¼" NPT	4"	6,000	.050
½" NPT	2"	5,000	.035
½" NPT	2"	8,000	.050
½" NPT	2½"	5,000	.035
½" NPT	2½"	8,000	.050
½" NPT	3"	4,000	.035
½" NPT	3"	6,000	.050
½" NPT	4"	4,000	.035
½" NPT	4"	6,000	.050
½" NPT	6"	5,000	.050
½" NPT	8"	5,000	.050

FEATURES:
1. In, Out and Bleed ports: ¼" NPTF.
2. Maximum instrument air: 250 psi.
3. Pilot Valve head threads: ½" NPT for saddle connection.
4. Probe threads: ¼" NPT.
5. Probe maximum WP: See probe data pressure rating.
6. Probe design to customer's specifications.

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Fig. 1700-6 Simplified Wellhead Control for SSV



The valve consists of a gate assembly that operates at ninety degrees to the pathway through the valve. The valve stem and gate rise to effect closure. This stem action is opposite the stem action of a normal gate valve.

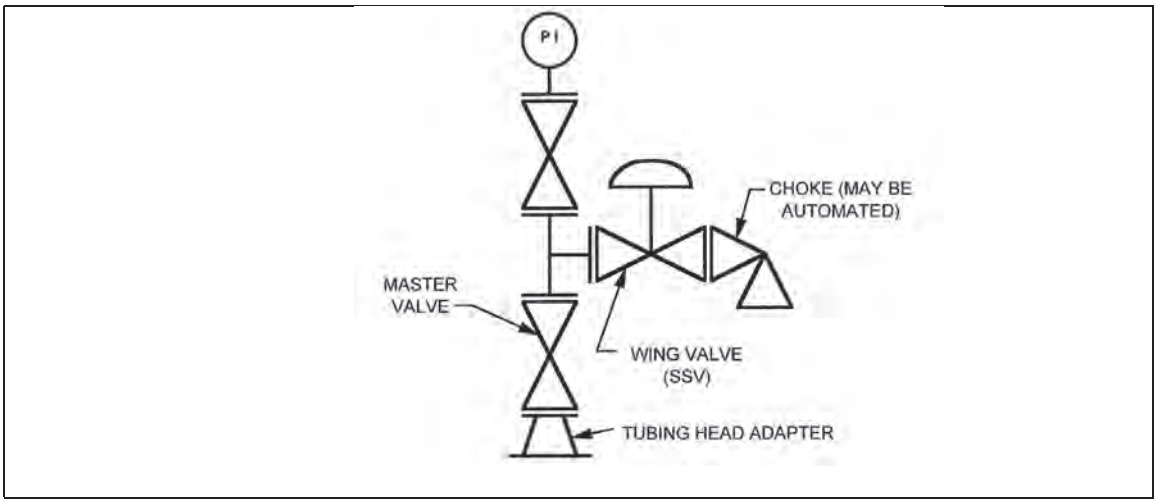
The internals of the valve are designed so that the body pressure generates a force on the gate and stem in the upward direction, always tending to drive the valve shut.

A diaphragm- or piston-type of actuator is used with a reverse gate valve. The valve is opened by applying pressure above the diaphragm, which drives the stem down. To close the valve, the pressure is removed from the diaphragm. The flowline pressure drives the gate stem upward, closing the valve. A spring, located below the actuator diaphragm, will also close the valve when equal pressure is present on both sides of the valve.

The actuator must be sized above the maximum anticipated operating pressure or for the maximum allowable working pressure (MAWP) of the valve itself. A safety

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Fig. 1700-7 Typical Wellhead Christmas Tree with SSV



factor of about 25% for wear and friction losses in the future should be added. Diaphragm actuators are presently used up to 15,000-psig design pressures.

Manual overrides for an SSV can be provided on land but are not allowed offshore. Three types are available:

- Hydraulic
- Handwheel
- Lockout cap

Lockout caps should be furnished with a fusible insert so that the valve will close in case of a fire.

A diaphragm-actuated valve is shown in Figure 1700-8. All surface safety valves should have a firesafe seal on the shaft and an external relief valve on the actuator housing. A fusible link has been installed on the pressure line to the actuator in some areas.

Many wellhead SSVs require a quick bleed or quick exhaust valve on long actuator supply lines to ensure that the valve closes quickly enough. See Figure 1700-9.

SSVs should be provided with some means to visually indicate to the operator whether the valve is open or closed.

1714 Surface-Controlled Subsurface Safety Valves (SCSSV)

SCSSVs are specially designed wellhead shutdown valves that are held open by the maintenance of a constant hydraulic pressure. These valves are usually located hundreds of feet below the bottom of the sea or surface of the land. Sometimes more than one valve is required per well.

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The valve is installed in the wellhead tubing and the hydraulic control tubing is run between the tubing and the intermediate casing. One type of SCSSV is shown in Figure 1700-10.

The number of wells being controlled by a hydraulic system depends upon local preference. Sometimes individual hydraulic systems are preferred. Usually the wells are grouped in logical “blocks” that enable good operator access and control in case of a problem. Normally, a limit of no more than 10 to 20 wells per hydraulic system will allow all the SCSSVs to be reset in under 5 minutes.

Hydraulic pressure is supplied by a pneumatically driven pump with a second pump as a backup. The backup pump can be another pneumatically driven pump with a manual operator option or just a manually operated pump.

A low-pressure sensor can be installed to monitor the hydraulic pressure and alert the operator. A relief valve is provided on the discharge of the pump to relieve excess back pressure back to the supply tank. The main pump is driven by approximately regulated 100-psig air or natural gas.

Regulations such as API RP 14B and OCS Order No. 5 govern the requirements for these systems.

Control of SCSSVs

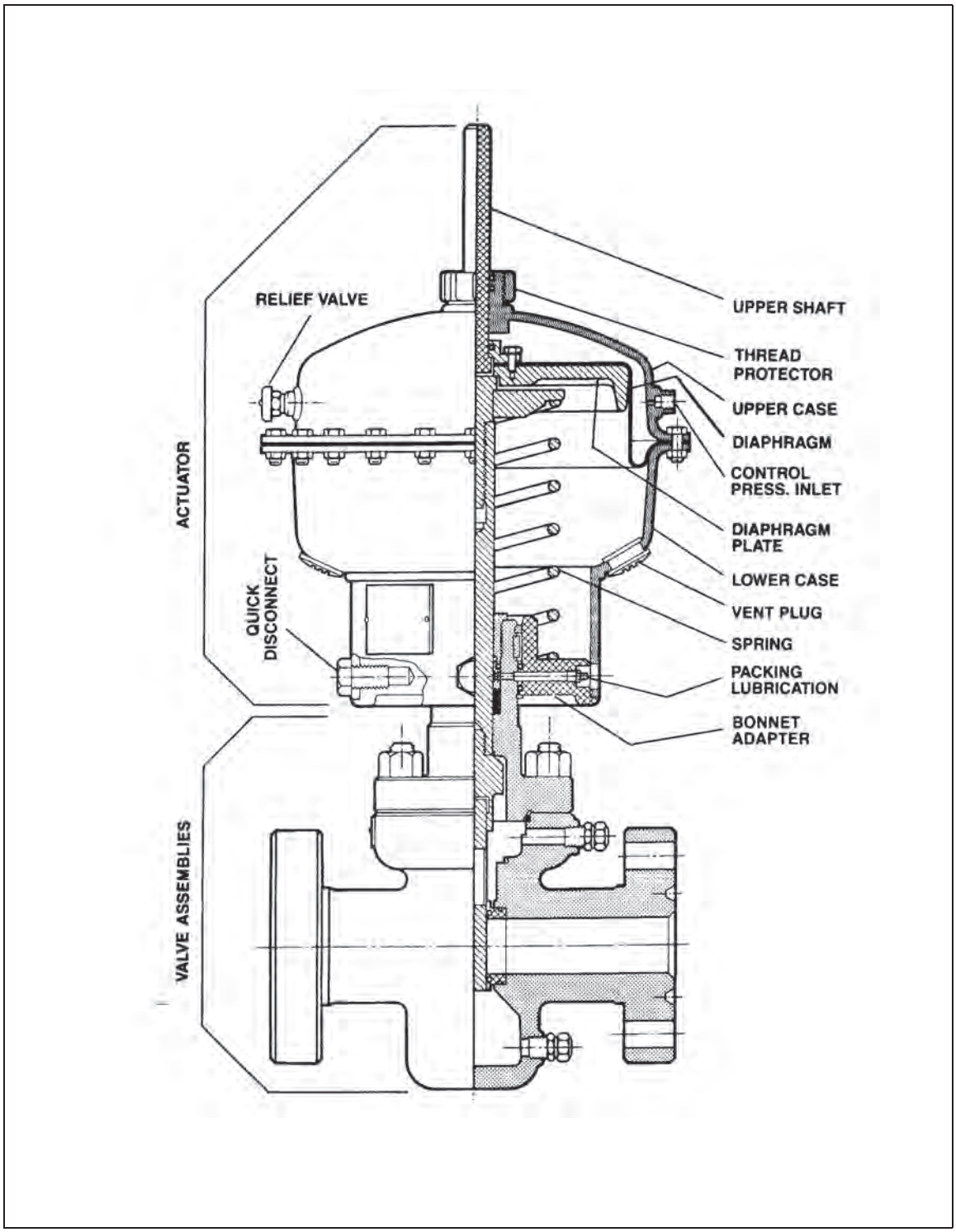
Each well should have its subsurface controls located in the control panel, adjacent to the surface controls. A typical hydraulic circuit for an SCSSV is shown in Figure 1700-11.

To operate the control system in order to open the SCSSV and the SSV, the following sequence occurs:

1. By pulling the knob, the operator manually resets the pilot relay for the hydraulic system (MR-1). The pin will hold the relay open.
2. Instrument gas will flow through the ESD/Fire Loop pilot relay (R-2), and
    a. Pressure up relay MR-1 and release its pin
    b. Pressure up the hydraulic system latching relay (R-3) and allow gas to flow to the hydraulic pumps
    c. Start the pneumatically driven hydraulic pump and
    d. Close the hydraulic dump valve (R-4)
3. The selected SCSSVs will open and at the shut-in tubing pressure (SITP) the hydraulic low-pressure switch will allow instrument gas to flow to the hydraulic pressure pilot relay (R-5).
4. Instrument gas will flow through R-5 and through the process equipment S/D pilot relay (R-6) and will pressure up the field flowline instrument tubing up to the pressure-switch-low (PSL) switch.

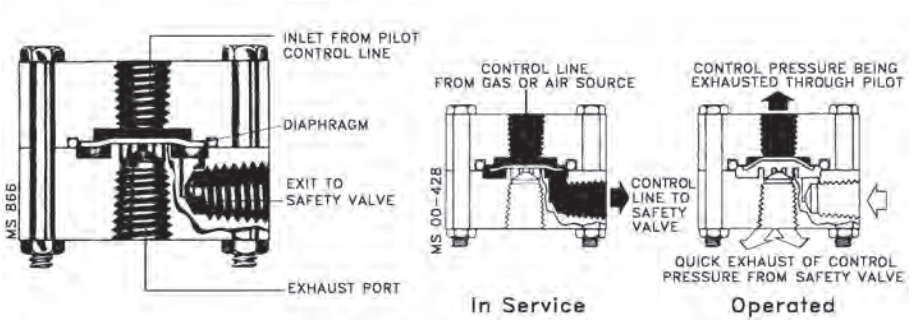
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Fig. 1700-8 Typical SSV with Diaphragm Actuator *(Courtesy of Axelson, Inc.)*



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Fig. 1700-9 Quick Bleed or Exhaust Valve *(Courtesy of Otis Engineering Division of Halliburton)*



5. After confirming that the first SCSSV is open, the operator pulls the knob to manually reset the pilot relay for the first SSV (MR-7-1). The pin will hold the relay open.

6. 100 psig instrument gas will flow through MR-7-1 to the quick exhaust valve and open the SSV.

7. After the first well is sending crude oil to the process equipment, instrument gas will flow through the PSL switch and the sand probe and back to the SSV pilot relay (MR-7-1), where the pin will release.

8. The second well is put onstream the same way by manually resetting the SCSSV selector and confirming that the SCSSV is open, then resetting the SSV pilot relay (MR-7-2), etc., until all the wells are flowing.

Hydraulic Pumps

Most hydraulic pumps are air or natural gas driven reciprocating pumps. Electrically driven pumps are occasionally used. As shown in Figure 1700-12, the gas power end has a larger area than the liquid end. The pump reciprocates due to the action of a cycling gas supply.

The maximum discharge pressure of the liquid at no flow is approximately equal to the pneumatic supply pressure times the area ratio plus the liquid suction pressure. When this balance of forces is reached, the pump stalls and ceases pumping without consuming any supply gas. The pump will automatically restart when the hydraulic pressure drops below 97% of the design pressure.

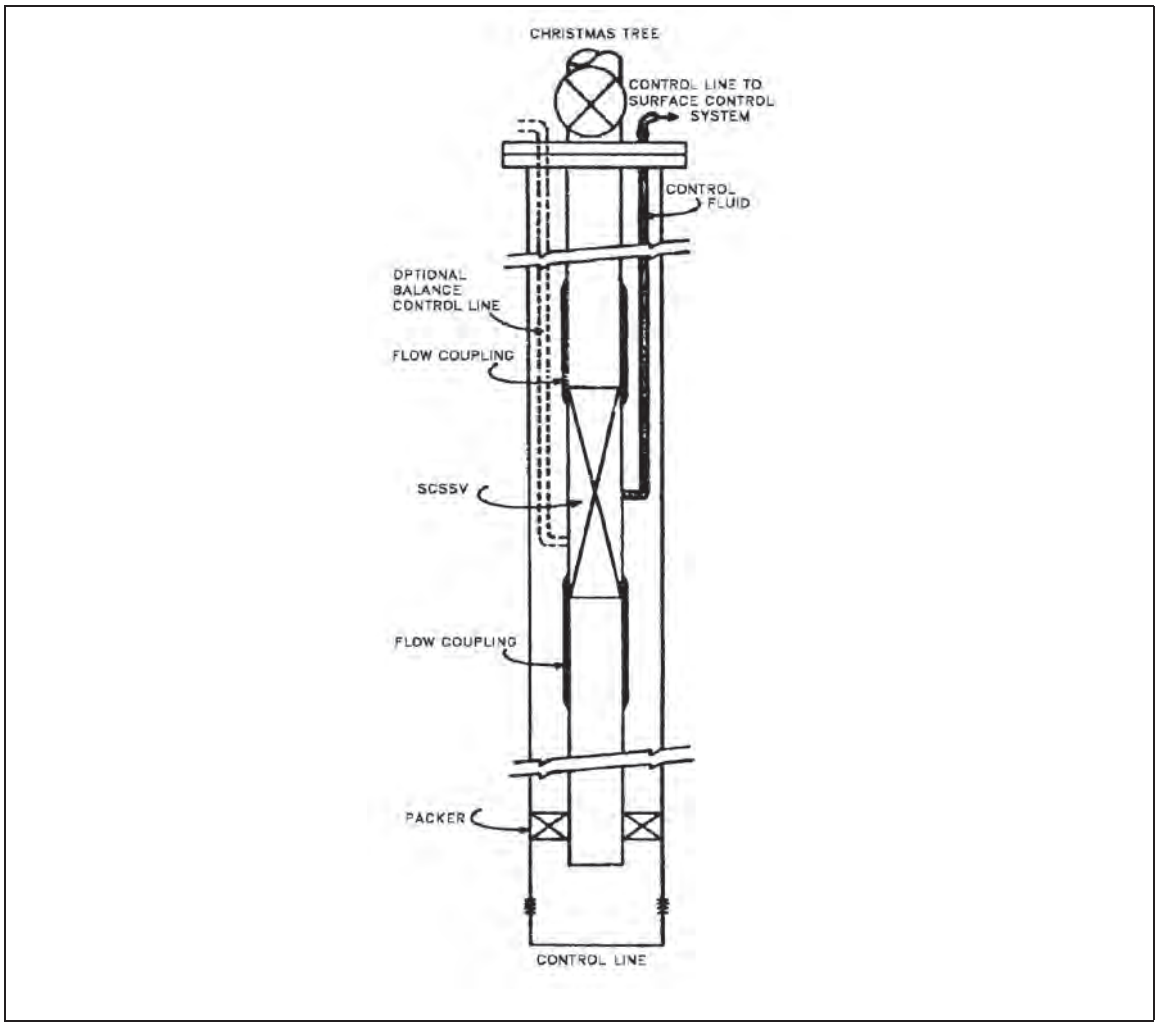
Normally, a backup manually operated hydraulic pump is used for maintenance or emergency use to keep the SCSSV open.

Time Delays to Close SCSSV

A remote emergency shutdown from the platform ESD system must shut down the SCSSV, but only after a nominal 2-minute time delay.

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Fig. 1700-10 Typical SCSSV *(Courtesy of the American Petroleum Institute)*



This delay will ensure that the SSV at the wellhead is closed first to allow it to absorb the wear and tear of opening and closing against a differential pressure at flowing conditions. The SSV is much easier and cheaper to repair than the SCSSV.

The time delay, which is adjustable, is accomplished by adding a needle valve and volume bottle in the pneumatic ESD signal line going to a pilot relay that controls the air or gas to the hydraulic pump and dump valve. The orifice in the needle valve restricts the air or gas bleed to the piston of a pilot relay. After about 2 minutes, the three-way valve in the relay will shift and depressure the system. This action will open the hydraulic dump valve, which quickly allows the hydraulic pressure on the SCSSV to be relieved to the supply tank. Refer to Figure 1700-13.

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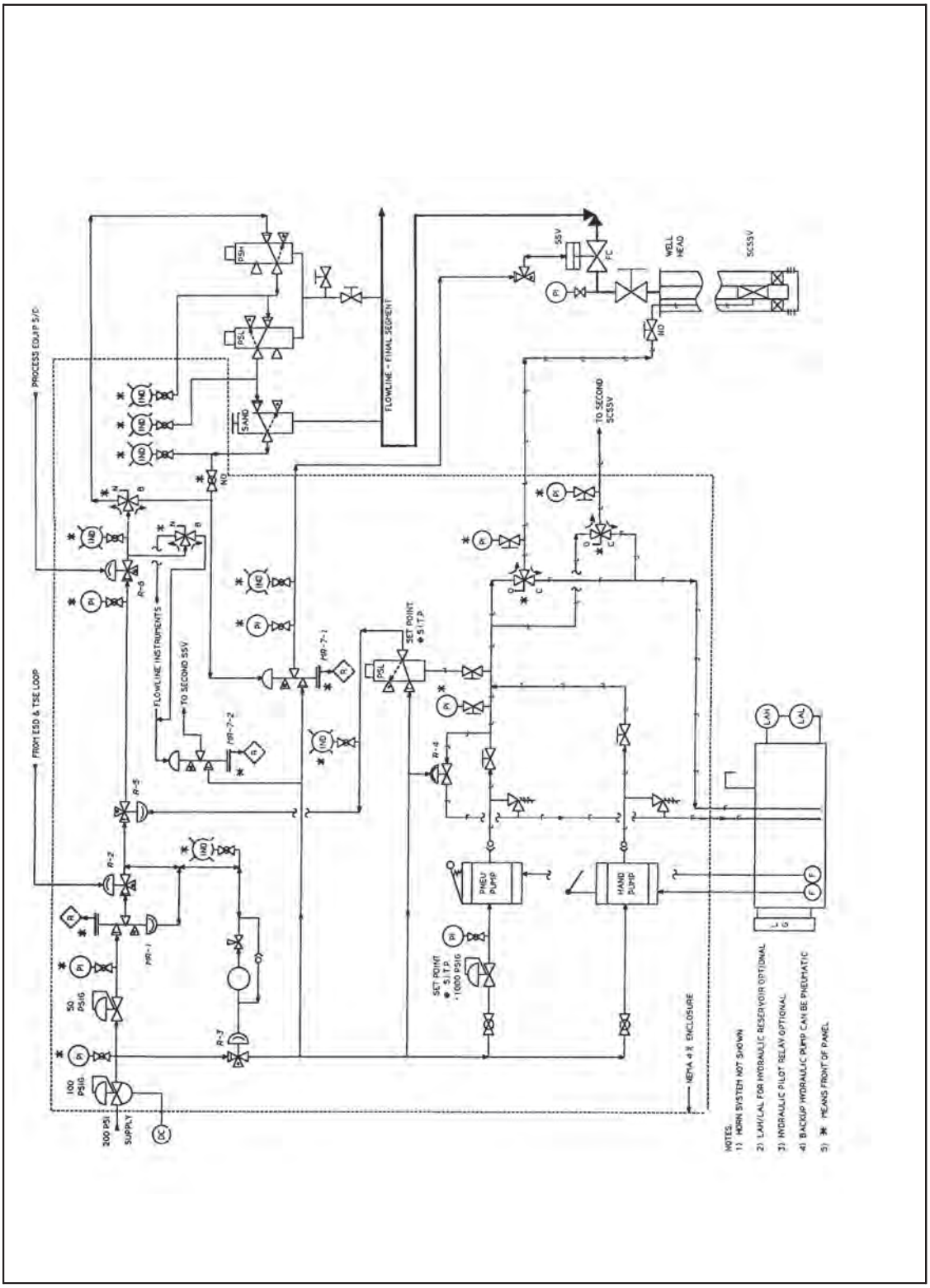


Fig. 1700-11 Typical Hydraulic Circuit for SCSSV

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Fig. 1700-12 Schematics of Basic Pump Types

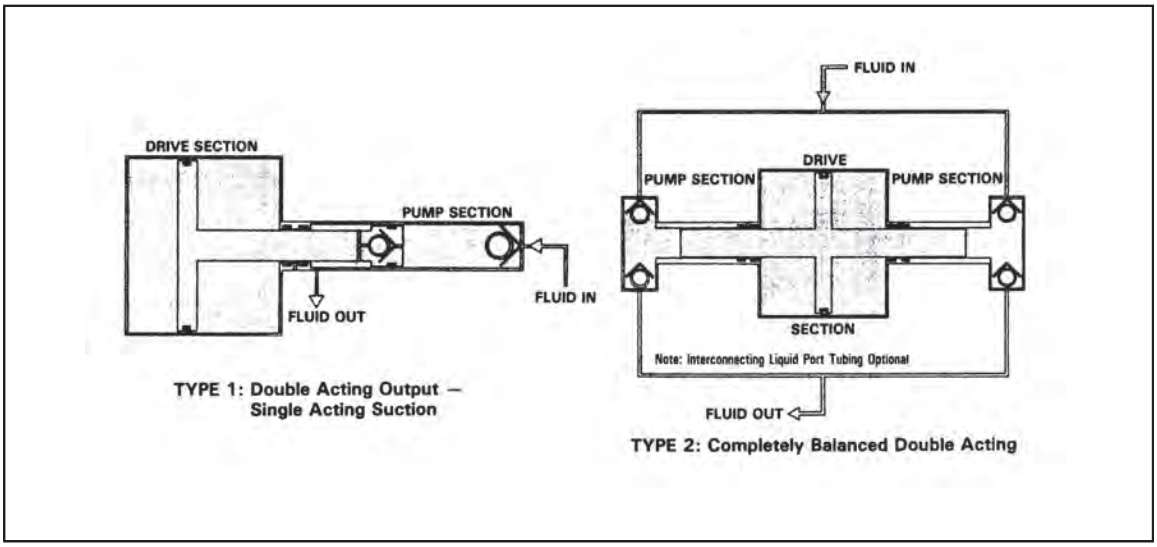
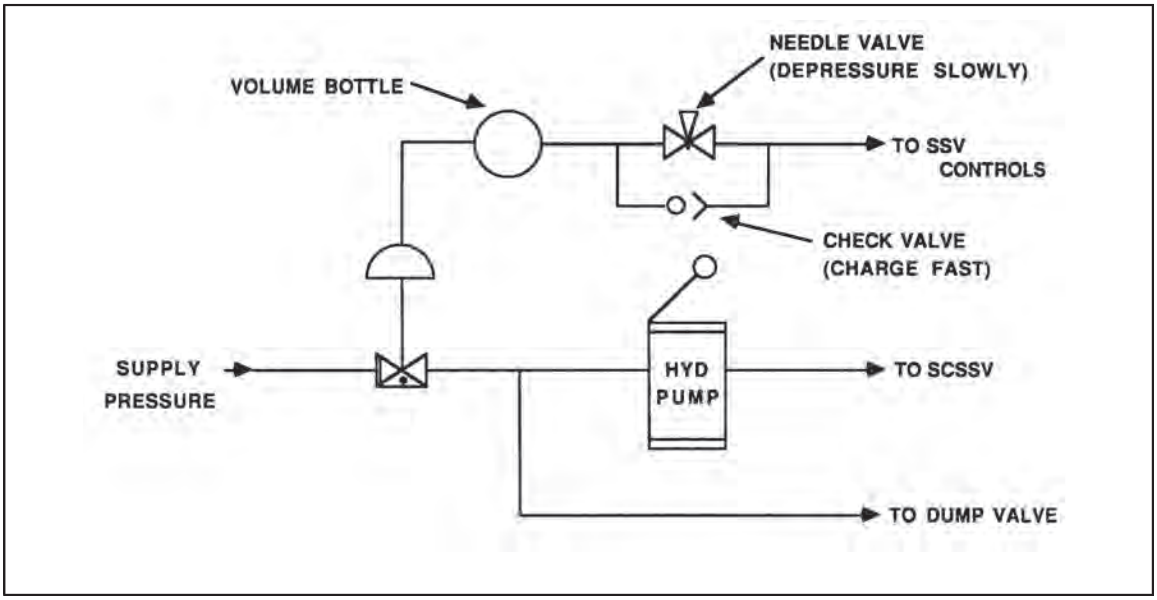


Fig. 1700-13 Time Delay Circuit to Close SCSSV Slowly



Safety Interlock to Open SCSSV First

The SCSSV must have a safety interlock to make sure that this valve is opened before the SSV. The SCSSV is extremely difficult to open when there is a maximum differential pressure across the valve, which would be true if the SSV were opened first.

The addition of a pilot relay in the pneumatic circuit is the method usually used to provide the safety interlock. Pressure is thereby supplied to the hydraulic pump

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supply pressure, the hydraulic dump valve, and the supply port of the manual reset pilot relay that controls the SSV.

Other Safety Interlocks and Features

Low- and high-level alarms on the main hydraulic reservoir tank are normally included to alert the operator that a hydraulic leak or backflow of process fluids from the well through the control tubing has occurred.

The hydraulic fluid reservoir must be adequately vented to prevent any pressure buildup caused by returning fluid during an emergency shutdown of all the SCSSVs, or in case of backflow from the well through the control tubing.

A low-pressure alarm on the automatic hydraulic pump discharge alerts the operator of a pump malfunction before the SCSSVs all close against operating wells.

Exact requirements for surface-controlled systems for SCSSVs used on offshore platforms are covered in API RP 14B and shown in Figure 1700-14.

1720 Design Considerations

1721 Flowline Pressure Rating, Ten Foot Rule

Flowlines transport hydrocarbons from the wellhead to the first downstream process equipment or vessel. Flowlines are divided into flowline segments. A flow-line segment is a portion of the flowline that has an assigned operating pressure from the other portions of the flowline. Thus, most wells have an initial and a final segment with an inline pressure reducing device or choke separating the segments.

API RP 14C Section A1 describes the requirements for safety devices and their location for offshore platforms. These rules follow the Company requirements and should apply on land as well as offshore. The following discussion is an abbreviation of RP 14C. It assumes that the flowline has only one choke and therefore is divided into two segments. Refer to Figure 1700-15.

Two important considerations determine the requirements for safety devices on wellheads and flowlines.

- Is the first choke device in the initial flowline segment less than 10 feet from the wellhead?
- Is the maximum allowable working pressure of the final flowline segment (after the choke) greater than or less than the shut-in tubing pressure (SITP) of the well?

When the distance to the choke is less than 10 feet, then pressure sensors in the initial segment of the flowline upstream of the choke are not required. When the distance is greater than 10 feet, then API RP 14C only requires a low-pressure sensor to detect leaks and ruptures. High- and low-pressure sensors are always required in the final flowline segment downstream of the choke. When the maximum allowable working pressure (MAWP) of the final segment of the flow-

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line after the choke is greater than the shut-in tubing pressure (SITP), then both high- and low-pressure sensors are required to detect a blocked line or flow control failure as well as a leak or rupture.

However, when the MAWP of the final flowline segment is less than the SITP, then a pressure relief valve as well as both high- and low-pressure sensors are required. This requirement follows the concept of an independent backup device discussed in Section 1300, "Process Alarm and Shutdown Systems."

In the previous case, where the MAWP of the final segment is less than the SITP, API RP 14C allows the substitution of a second shutdown valve and an independent high-pressure sensor in place of a pressure relief valve.

If the flowline has no choke then the MAWP for the entire flowline must be greater than the SITP. Both high- and low-pressure sensors are required in this case where there is only one segment.

Flowlines may have more than two segments. API RP 14C should be consulted to determine the required safety equipment.

For all flowlines, the following safety devices should be included:

- Check valve in the final flowline segment to prevent any backflow
- ESD shutdown
- Fire loop shutdown
- Downstream process equipment shutdown

In some locations fusible plugs have been installed in the pressure line to the SSV actuator and in other locations they have been installed inside every control panel.

1722 First Out Indication

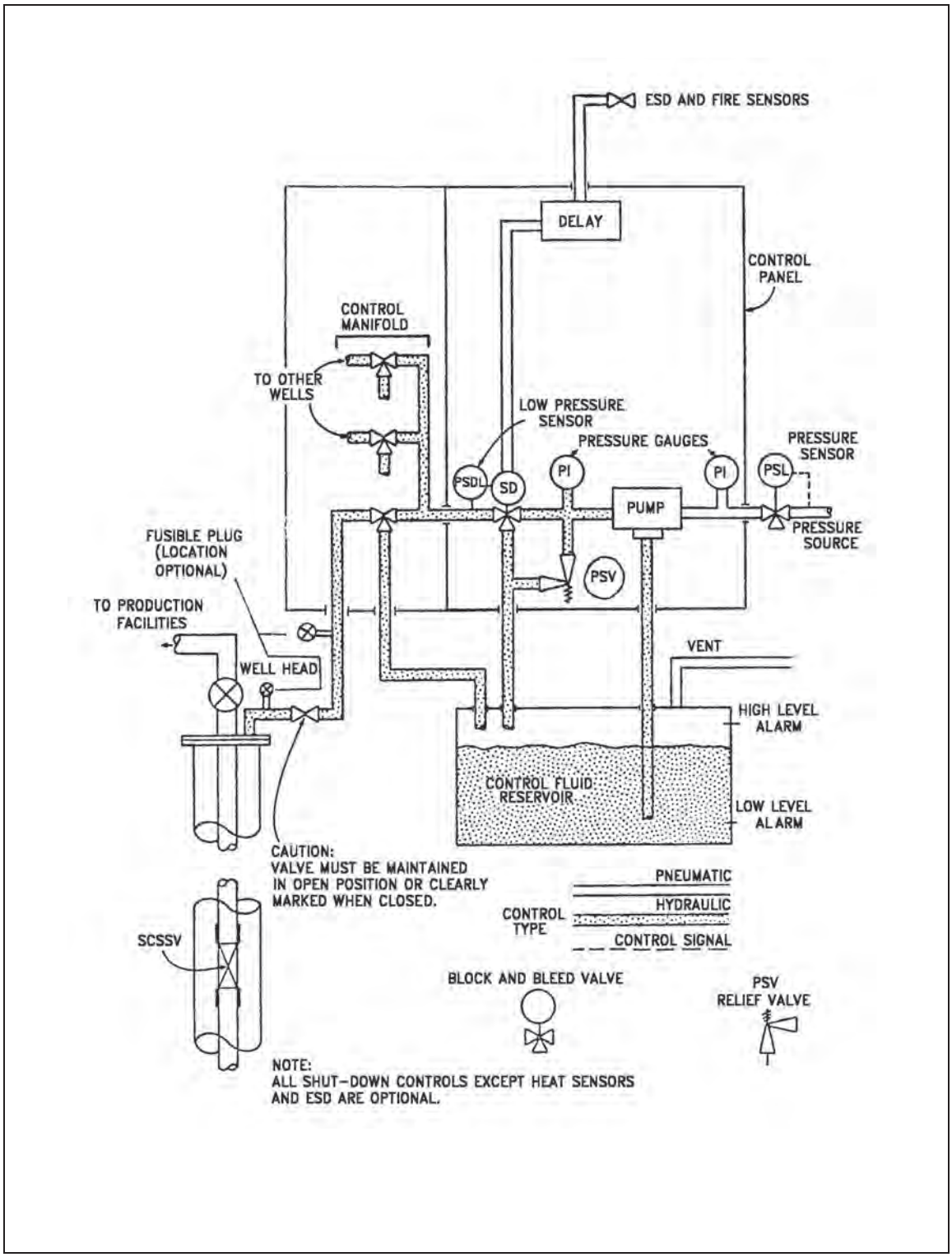
If three sensors are used to shut down the surface safety valve (e.g., high-pressure, low-pressure, and sand probe), then first out indication may be desirable. Most wellhead control panels in the Company have not required this feature in the past, but new installations are beginning to put them in.

First out indicators can help during the testing of pressure sensors, especially when multiple wellhead control panels are installed. The sensors are mounted on the flowline and pilot relays are installed in the wellhead control panel. Panel indicators are connected to the outlet port of each of the pilot relays. From written instructions, the operator can determine which sensor tripped by observing the number of tripped indicators. The knob on the sand probe could also be used as an indicator, but because it is mounted remotely, it may not be visible from the panel.

A better way to do the same thing is to install first out indicators (e.g., Amot Model 4400) which have internal porting and will only indicate the sensor that tripped. See Figure 1700-16.

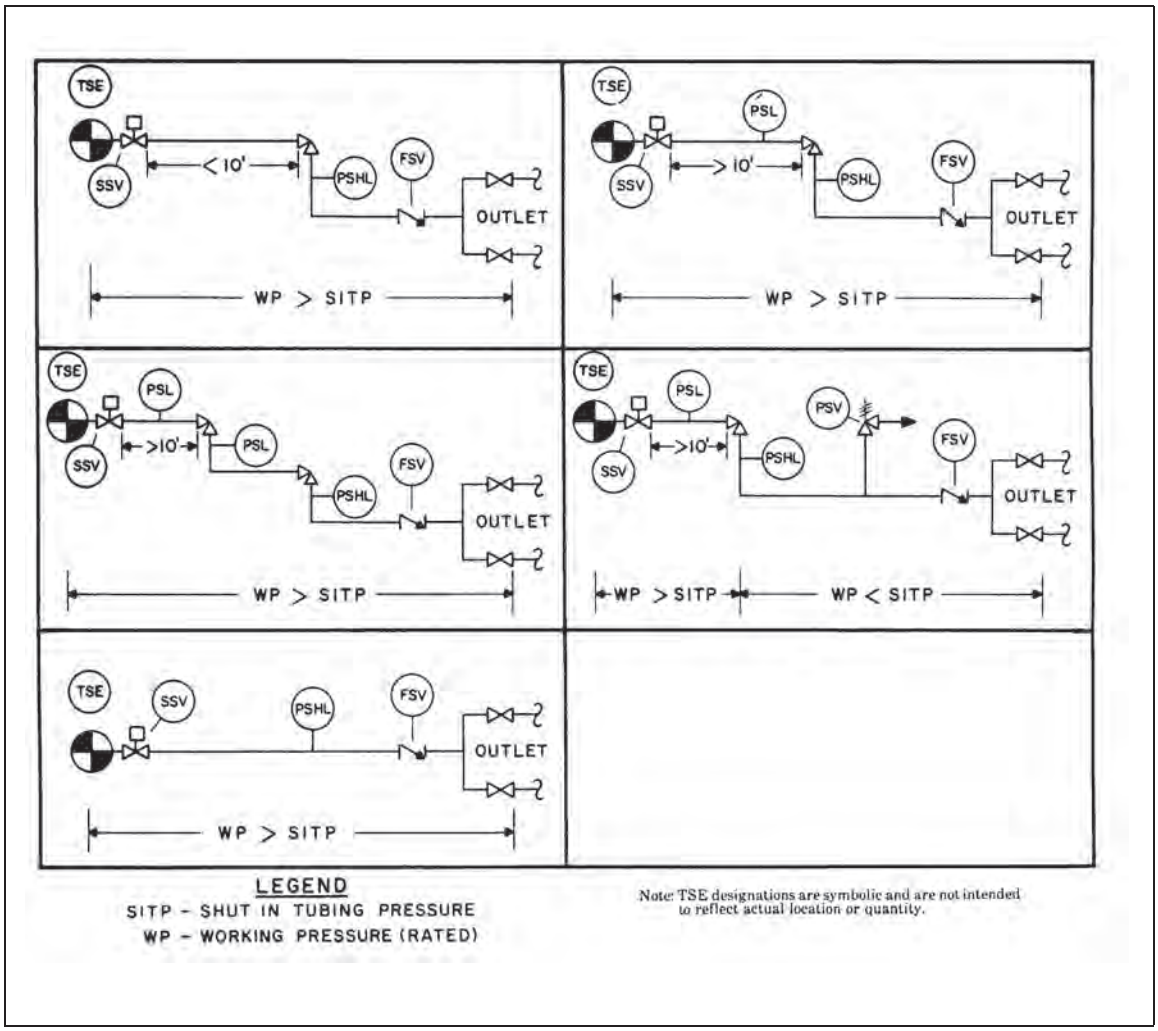
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Fig. 1700-14 Schematic of a Control System for SCSSVs *(Courtesy of the American Petroleum Institute)*



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Fig. 1700-15 Recommended Safety Devices for Wellhead Flowlines *(Courtesy of the American Petroleum Institute)*



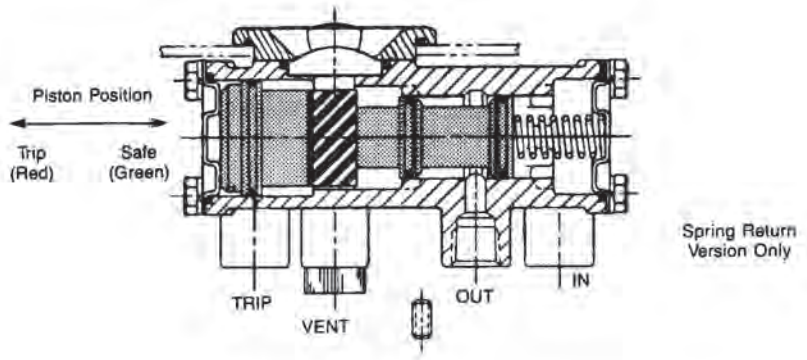
1723 Testability and Maintenance During Operation

A three-way valve on the panel can be installed to bypass the high- and low-pressure pilots and the sand probes while sensors are being tested, calibrated, or replaced. For safety reasons, it should be very evident from a distance that the bypass valve has been switched by the use of panel-mounted indicators. Many facilities require an alarm when bypass switches are used. Sometimes individual bypass valves for each of the three sensors are used.

A test connection in the field should be provided for checking the pressure sensors. Individual barstock root valves and test valves are normally used. When oil quality allows the pressure pilots to be panel-mounted, then the test connection can be panel-mounted also.

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Fig. 1700-16 Pilot Relay with First Out Indication *(Courtesy of Amot Controls Corp.)*



When a fault condition arises, the valve sensing that condition opens, causing a loss of pressure at the large end of the piston and allowing pressure on the small end to move the piston to the "Red" or tripped position. The OUT Port connects with the VENT Port through specially formed vent grooves, and all pressure downstream is released to the VENT as the IN Port is closed off from the OUT Port. This loss of pressure can be used to close fuel valves, actuate audible alarm devices or operate remote signal devices or switches. Any indications existing at that moment will be held indefinitely. The unique Red and White striped "Trip" tape, selected by optical specialists, can be clearly seen at a distance even in poor light and by those with impaired color vision. An operator can check the 4400 Relay panel at any time and tell immediately what caused the trouble.

Needle valves in the supply gas and hydraulic oil tubing runs should be provided to allow components to be replaced without requiring that an individual wellhead or all the wellheads be shut down. Some of the components which may require replacement are as follows:

- Pressure regulators
- Pressure gages
- Indicators
- Hydraulic pumps and their regulators

1724 Panels for Wellhead Controls

Several vendors specialize in building wellhead control panels. In order to be competitive, they will offer to supply the minimum number and lowest quality of logic and panel components.

To get a panel that is reliable and maintainable, a drawing should be prepared that shows in general terms such things as the following.

- Available space that the panel can occupy or the maximum acceptable panel dimensions

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- Accessibility to the panel for maintenance and the location of doors and bulkheads
- General layout of the controls showing the wellhead control groupings, the location of subsurface controls for each well in relation to the surface controls, and the location of the hydraulic control unit and manual pump override
- The minimum and maximum height of the controls from grade and how the panel is to be mounted
- The amount of space required for expansion
- Nameplate engraving details including the lines of text, the size of letters and nameplate, and color scheme, if any
- Distances from the field devices to the panel
- Indication requirements for such things as valve status and bypass switches
- Bypass switch and test valve requirements
- First out indication requirements for shutdown sensors

The drawing or an attached specification should include a list of the components and the acceptable manufacturers.

To ensure quality and reliability, it is often necessary to include model numbers to avoid the problem when a vendor supplies the least expensive option. Model numbers also help in bid evaluation, during inspection of the finished panels, and to maintain standardized spare parts.

Vendors should be allowed to offer reasonable substitutions in order to produce the lowest cost panel by avoiding unusual construction requirements.

1725 Enclosures for Wellhead Control Systems

Enclosures are usually made of 316 stainless steel to withstand the corrosive environment of offshore platforms or the workover conditions around the wellheads. As a minimum, all the hardware must be made of 316 stainless steel. This includes hinges, latches, handles, bolts, and nuts.

Enclosures may be made to withstand such things as windblown rain, sand, and dust; splashing water; hose-directed water; and spray from wellhead workover activities. External icing may also be a problem, but it is usually handled by the use of buildings or shelters.

Specifications may be written to describe the enclosure construction required to withstand operating conditions, but the use of NEMA-type enclosures, developed for electrical equipment, can match the right cabinet or enclosure to the operating conditions. Some of the NEMA types are as follows.

NEMA 13 — indoor use, protection against dust, spraying of water, oil, and noncorrosive fluids.

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NEMA 12 — indoor use, protection against dust, falling dirt, and dripping noncorrosive liquids.

NEMA 3 — outdoor use, protection against windblown dust, rain and external icing.

NEMA 3R — outdoor use, protection against falling rain, external icing, and only rust resistant

NEMA 4 or 4X — outdoor use, protection against windblown dust and rain, splashing water, hose-directed water, and external icing. (The "4X" means corrosion-resistant, but "316 stainless steel" should be added to this description.)

Following are some other important requirements for construction.

- Tubing runs between components should be designed to allow easy removal of components or in-place maintenance to replace "O" rings and gaskets.
- Stacking or double layering of tubing runs should not be allowed.
- Longer tubing runs should be clamped with solid stainless steel spacers.
- All tubing should be reamed and blown clean with dry air before installation.
- Pipe-to-tube fitting adapters should be used to connect components instead of pipe nipples and unions.
- All penetrations or bulkhead fittings should be on the sides, back, or bottom. No penetrations should be allowed into the top of the enclosure.
- No internal components should be mounted from the top or bottom of the enclosure.
- When height or width exceeds 36 inches, then construction should be with at least 12-gage stainless steel. Otherwise 16-gage metal is satisfactory.
- Gaskets should be made of oil- and water-resistant material such as neoprene.
- Gaskets should be secured with an oil-resistant adhesive and supported by continuous stainless steel retainer strips.
- The bottom should be sloped, with a 1/2-inch flush-mounted half-coupling for draining.
- Lifting eyes with reinforced plates should be provided to support the entire weight of the completed panel for installation.
- Mounting brackets or stands (including nuts and bolts) should be provided for small enclosures that are less than 48 inches tall.
- Integral legs should be provided for free standing enclosures 48 inches or taller, including hardware to bolt the legs to the floor.
- If earthquake requirements exist, brackets should be provided for securing tall enclosures.

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- Number and size of doors should be specified and should depend on the width of the enclosure. If it is wider than 36 inches, multiple doors are required, with a maximum width for each door of 30 inches.
- If the type of door latch is not specified as NEMA 4X, three-point latches made of stainless steel are typically used.
- Locks or other features should be provided for security.
- Mounting and bracing of all internal components should be provided to prevent damage during shipment and installation and from operating conditions such as vibration. These supports and shelves are usually made from a corrosion-resistant material such as stainless steel.
- All clips, clamps, straps, bolts, nuts, washers, screws, etc., should be made of 316 stainless steel, nylon, or some other durable, corrosion-resistant material.
- It may be desirable to have a panel or even individual compartments to separate hydraulic systems from pneumatic systems.
- When potentially hazardous or corrosive gasses are being handled, the design of the control system should prevent them from entering any panels or enclosures.

1726 Tagging and Nameplates

Nameplates and tagging are very important for the factory checkout of the panel, the installation of the panel, safe operation of the controls, and maintenance troubleshooting of the wellhead control system.

These are some important considerations:

- All internal components should be tagged with the instrument number or the identification number on the schematic drawing. If the component does not have permanent markings giving the make and model number, then this information should be added to the tag. Tags should be of stainless steel and wired or attached onto the components by a corrosion-resistant fastener. Panel-mounted devices should have these tags attached to the device and visible from the inside of the panel.
- All panel-mounted instruments including pressure gages, valves, indicators, pilot relays, etc., must have engraved Bakelite or plastic nameplates that clearly identify the device.
- Engraved tags should have black letters in a white (or other color if a color scheme is used) background so that they can be easily cleaned. They should be attached with stainless steel screws.
- Nameplates should be engraved from a nameplate schedule or front of panel drawing. They should include the tag number, a process function, and any operating instructions (e.g., “Pull To Reset”).

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- These tags are often color coded. Possible color groups are surface safety shut-down controls; subsurface safety controls including the hydraulic system; and bypass and ESD switches.
- Panel title nameplate should have 3/4-inch letters at a minimum and should identify which wells in the area or wellbay are being controlled. The controls for each well should be clearly grouped and identified.
- Each bulkhead connection should be identified with a stainless tag that is drilled and mounted under the bulkhead connection fitting. These tags should be mounted both on the outside and inside of the bulkhead. The tags should include the instrument number or schematic identification number.
- Panel drawings, including a schematic and parts list, should be enclosed in a weatherproof envelope and put in a pocket in one of the doors. On the inside of the panel should be a stainless steel or phenolic tag with the supplier's name, date of manufacture, vendor job number, Company purchase order number, and a list of the panel drawing numbers that could be useful to anyone trouble-shooting the panel.

1727 Functional Requirements

Project descriptions should detail the factory testing procedures, as well as who is responsible for the field installation of the panel, who is responsible for supplying the field devices, and who is responsible for the field commissioning of the panel connected to the field devices.

A preliminary simplified schematic diagram should be prepared. The simplified schematic need only show the key devices in the control system, like the pressure regulators, pressure sensors, sand probes, pressure gages, SSV and SCSSV, manual reset pilot relays for the safety valves, and bypass switches for any sensors.

For offshore installations, these requirements should be emphasized:

- Interlock for each well to make sure that the SSV cannot be opened before the hydraulic system is operational for opening the SCSSV valves
- Interlock for each well to make sure the SCSSV closes two minutes after the SSV
- Interlock to make sure the SCSSV closes only on an ESD or fire loop signal
- Minimum capacity of the hydraulic reservoir, a level glass gage visible from the outside of the enclosure, and external fill and drain lines
- When an SCSSV is opened, the design of the hydraulic system should prevent a pressure drop to any previously opened SCSSVs
- Type of backup pump and manual override to the main hydraulic pump.

Optional functionality should then be described in text form. The description should include the following.

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- Dual supply regulators and filters with isolating valves for each pressure system. (Each regulator should be capable of supplying the entire panel capacity.)
- Pressure requirements for the system including pressure of the supply gas and a description (e.g., natural gas, air, or nitrogen); gas pressure used to operate the SSV; holding circuit pressure for the pilot relays, etc.
- Number of bypass switches for the field sensors plus indication or alarm requirements for the bypass condition
- List of types of panel devices that should be equipped with isolating valves so that they may be replaced without shutting down other wells
- Size of the tubing and the wall thickness required for each pressure service
- First out-type of indicating pilot relays

SCADA System Requirements

Many wells are tied into a SCADA or production information system. Requirements for these electrical tie-ins should be reviewed during the panel design to make sure they are incorporated into the design, construction, and testing of the panel and field devices such as the wellhead SSV valves.

Information sent to SCADA system usually includes:

- Open and closed status of wellhead valve from position or proximity switches
- Operation of bypass switches around flowline pressure sensors

1730 References

1. API RP 14B, *Recommended Practice for Design, Installation, and Operation of Subsurface Safety Valve Systems.*
2. API RP 14C, *Recommended Practice for Testing of Basic Surface Safety System on Off-shore Production Platforms.*
3. API Spec 14D, *Specification for Wellhead Surface Safety Valves and Underwater Safety Valves for Offshore Service.*
4. API RP 14F, *Recommended Practice for Design and Installation of Electrical Systems for Offshore Platforms.*
5. Department of Interior, Minerals Management Service (MMS), OCS Order No. 5, *Subsurface Safety Devices.*
6. Chevron Overseas Petroleum General Specifications GS 11.08-1, *Alarm Systems.*
7. Chevron Overseas Petroleum Design Practice DP 11.08-1, *Wellhead Controls.*
8. NEMA Standards Publication No. 250.

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