

Process Measurement Instrumentation

API RECOMMENDED PRACTICE 551
FIRST EDITION, MAY 1993

REAFFIRMED, FEBRUARY 2007



AMERICAN PETROLEUM INSTITUTE

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Manufacturing, Distribution and Marketing Department

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Asbestos is specified or referenced for certain components of the equipment described in some API standards. It has been of extreme usefulness in minimizing fire hazards associated with petroleum processing. It has also been a universal sealing material, compatible with most refining fluid services.

Certain serious adverse health effects are associated with asbestos, among them the serious and often fatal diseases of lung cancer, asbestosis, and mesothelioma (a cancer of the chest and abdominal linings). The degree of exposure to asbestos varies with the product and the work practices involved.

Consult the most recent edition of the Occupational Safety and Health Administration (OSHA), U.S. Department of Labor, Occupational Safety and Health Standard for Asbestos, Tremolite, Anthophyllite, and Actinolite, 29 *Code of Federal Regulations* Section 1910.1001; the U.S. Environmental Protection Agency, National Emission Standard for Asbestos, 40 *Code of Federal Regulations* Sections 61.140 through 61.156; and the U.S. Environmental Protection Agency (EPA) rule on labeling requirements and phased banning of asbestos products, published at 54 *Federal Register* 29460 (July 12, 1989).

There are currently in use and under development a number of substitute materials to replace asbestos in certain applications. Manufacturers and users are encouraged to develop and use effective substitute materials that can meet the specifications for, and operating requirements of, the equipment to which they would apply.

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Process Measurement Instrumentation

SECTION 1—GENERAL

1.1 Scope

The material in Sections 2–6 was previously presented in several sections of Part 1 of API Recommended Practice 550, which is now out of print:

- a. Section 2—API Recommended Practice 550, Part I, Section 1, “Flow.”
- b. Section 3—API Recommended Practice 550, Part I, Section 2, “Level.”
- c. Section 4—API Recommended Practice 550, Part I, Section 4, “Pressure.”
- d. Section 5—API Recommended Practice 550, Part I, Section 3, “Temperature.”
- e. Section 6—API Recommended Practice 550, Part I, Section 8, “Seals, Purges, and Winterizing.”

The procedures for installation of the instruments covered in this recommended practice are based on experience with and evaluation of many installations. They represent the installation practices that yield the most consistently accurate results and have proved to be practical and safe.

Process and environmental protection is covered in a general fashion in Section 6. Where required, specific instances of process and environmental protection are covered in Sections 2–5.

Tank gauging is outside the scope of Section 3. The applicable publication is referenced in that section.

Where appropriate, installation drawings, cautionary notes, and explanations are included. Valves and piping that are typically covered in piping standards have been omitted from most installation drawings.

1.2 Referenced Publications

The latest edition or revision of the following standards, codes, and specifications shall, to the extent specified, form a part of this recommended practice:

ANSI¹

MC 96.1 *Temperature Measurement: Thermocouples*

API

RP 550 *Manual on Installation of Refinery Instruments and Control Systems, Part I, “Process Instrumentation and Control,”* Section 7, “Transmission Systems” (out of print)

RP 550 *Manual on Installation of Refinery Instruments and Control Systems, Part III, “Fired*

Heaters and Inert Gas Generators” (out of print)

RP 552 *Signal Transmitters and Air Supplies* (in press)

RP 554 *Control Centers, Instruments, and Control Systems* (in press)

RP 555 *Process Analyzers* (in press)

Std 606 *Compact Carbon Steel Gate Valves—Extended Body*

Publ 2218 *Fireproofing Practices in Petroleum and Petrochemical Processing Plants*

RP 2350 *Overfill Protection for Petroleum Storage Tanks*

Std 2545 *Method of Gaging Petroleum and Petroleum Products*

Manual of Petroleum Measurement Standards, Chapter 4, “Proving Systems”; Chapter 5, “Metering”; Chapter 6, “Metering Assemblies”; Chapter 7, “Temperature Determination”; Chapter 14, “Natural Gas Fluids Measurement,” Section 3, “Concentric, Square-Edged Orifice Meters,” Part 1, “General Equations and Uncertainty Guidelines”; Chapter 18, “Custody Transfer”

ASME²

B16.5 *Pipe Flanges and Flanged Fittings*

PTC 19.3 *Performance Test Code—Temperature Measurement*

ASTM³

STP 470B *Manual on the Use of Thermocouples in Temperature Measurement*

NFPA⁴

70 *National Electrical Code*

¹American National Standards Institute, 11 West 42nd Street, New York, New York 10036.

²American Society of Mechanical Engineers, 22 Law Drive, Box 2300, Fairfield, New Jersey 07007-2300.

³American Society for Testing and Materials, 1916 Race Street, Philadelphia, Pennsylvania 19103.

⁴National Fire Protection Association, 1 Batterymarch Park, P.O. Box 9101, Quincy, Massachusetts 02269-9101.

SECTION 2—FLOW

2.1 Scope

This section discusses recommended practices for the installation of the flow instruments commonly used in the refining process industry to indicate, record, and transmit flow measurements. Meter runs and custody transfer flow measurement are covered in Chapters 4, 5, 6, and 18 of the *API Manual of Petroleum Measurement Standards*.

2.2 General

2.2.1 CATEGORIES

Certain basic procedures, practices, and precautions apply to the flow instruments discussed throughout this recommended practice. Where applicable, the material covered in this section should be considered a part of the text of the discussions in subsequent sections. Common devices for flow measurement fall into the following categories:

- a. *Differential-head meters* measure flow inferentially from the differential pressure caused by flow through a primary element. Flow is proportional to the square root of the differential pressure produced. This differential is sensed by diaphragms, bellows, or manometers.
- b. *Variable-area meters (rotameters)* work on the principle that a float within a vertical tapered tube will assume a position that is a function of the flow rate through the tube from the bottom. The float must have a density greater than that of the measured fluid. The annular area through which the flow must pass is the difference between the internal area of the taper tube at the point of balance and the area of the float head. Since the internal area of the tube increases constantly and is continuously variable from bottom to top, whereas the float head area remains constant, the term *variable area* is used to describe this type of meter. At a constant differential pressure, flow is directly proportional to area.
- c. *Magnetic meters* are obstructionless meters that measure the volumetric rate of flow of any liquid that has the required electrical conductivity. Rate is determined using Faraday's law of electromagnetic induction.
- d. *Turbine meters* measure volumetric fluid flow with a pulse train output, the frequency of which is picked up magnetically from a rotor located in the flow stream and is linearly related to flow rate.
- e. *Positive-displacement meters* measure flow by mechanically trapping successive volumetric segments of the liquid passing through the meter body.
- f. *Vortex meters* use an obstruction in the flowing stream to generate a vortex train of high- and low-pressure areas.
- g. *Special meters* include devices such as mass (namely, coriolis and thermal), target, and sonic meters, which are often used for special applications. The manufacturers of these devices should be consulted regarding specific applications.

2.2.2 TRANSMISSION PRACTICE

Hydrocarbons or other process fluids should not be piped to any instruments located in a control room. Standard industry practice is to convert the flow measurement to an electrical or pneumatic signal and transmit the signal to remote receiving instruments. It is also standard practice to transmit the flow measurement in local installations where long piping or other methods would otherwise be required. Examples include cases in which solids present in the process fluid cause plugging or in which differences in elevation could result in head problems. Insulation and heating of long lines to prevent freezing are also minimized or eliminated by the use of transmission systems.

2.2.3 ACCESSIBILITY

All locally mounted flow instruments should be readily accessible from grade, platforms, fixed walkways, or fixed ladders. A rolling platform may be used where free access is available to the space below the instruments.

2.2.4 LOCAL INDICATION

Where local indication is desired and nonindicating transmitters are used, output indicators should be provided. In applications where flow can be manually controlled at a control-valve station, flow indication should be clearly visible and readable from the valve location to permit manual control when necessary. This flow gauge should not be used to calibrate the transmitter.

2.2.5 VIBRATION

Most instruments are susceptible to damage, abnormal wear, or malfunction if mounted in a location where they are subject to vibration. If any part of the flow system or equipment is subject to vibration, the affected instruments should be provided with vibration-free supports.

2.2.6 PULSATION

Measurement of pulsating flow is difficult and should be avoided. Head-type flowmeters and instruments with mechanical movements, such as positive-displacement meters and turbines, should not be used in pulsating-flow applications. The measurement is not dependable, and the pulsing may contribute to premature wear of the mechanical components.

2.2.7 PURGING AND SEALING

When viscous liquids or corrosive process fluids are measured, or if there is a possibility of plugging where solids or

slurries exist, sensing lines to the sensing head of the differential transmitter should be protected by means of a diaphragm seal or purged impulse lines. The diaphragm seal unit should have wetted parts suitable for the fluid measured, and the materials should be corrosion resistant (see Section 6).

2.2.8 PIPING

Process connections to the instruments should be furnished and installed in accordance with applicable piping and material specifications. All pipe should be deburred after cutting and blown clean of cuttings and other foreign material before assembly. As an alternative to pipe, tubing of suitable material may be used. This subject is covered in general by the project piping specification.

2.3 Measurement Devices

2.3.1 DIFFERENTIAL-PRESSURE METERS

2.3.1.1 Primary Elements

2.3.1.1.1 General

Differential pressure is the most commonly used method of flow measurement. Primary elements used to generate the differential pressure are generally one of the types described in 2.3.1.1.2 through 2.3.1.1.6.

2.3.1.1.2 Orifice Plate

The sharp- (square-) edged concentric orifice plate is the most frequently used element because of its low cost and adaptability and the availability of established coefficients. For most services, orifice plates are made of corrosion-resistant materials, usually Type 304 or 316 stainless steel. Other materials are used for special services. Eccentric orifices or segmental plates should be used for very dirty fluids or slurries or wet gases; quadrant orifices should be used for viscous liquids. Advantages of orifice plates include good repeatability, ease of installation, use of one transmitter regardless of pipe size, low cost, the wide variety of types and materials available, and the relative ease with which they can be changed. Limitations of orifice plates include their susceptibility to damage by foreign material entrained in the fluid and to erosion. A straight run of upstream and downstream piping is required for an orifice plate. For details on orifice plates, refer to Chapter 14, Section 3, Part 1, of the *API Manual of Petroleum Measurement Standards*.

2.3.1.1.3 Flow Nozzles

Flow nozzles are used less frequently than are orifice plates. Their principal advantages are good repeatability, low permanent head loss and approximately 65 percent greater flow capacity for a given diameter than can be obtained under the same conditions with an orifice plate, and use of one

type of transmitter regardless of pipe size. A straight run of upstream and downstream piping is required for a flow nozzle (see Figure 1). The limitations of flow nozzles are higher cost; lack of extensive data, compared with orifice plates; limited application on viscous liquids; and the fact that flow calibration is recommended.

2.3.1.1.4 Elbow Meters

Elbow meters are used in installations where velocity is sufficient and high accuracy is not required. Advantages of elbow meters include good repeatability, high level of economy, ease of installation, ability to be bidirectional, very low pressure loss, minimum requirement for upstream piping, and use of one type of transmitter regardless of pipe size. Limitations of elbow meters include their lack of fitness for low-velocity services, poor accuracy, and low differential for given flow rates.

2.3.1.1.5 Venturi and Flow Tubes

Venturi and flow tubes are used where high capacity and minimum head loss are critical factors. Their advantages are good repeatability, low permanent loss, applicability to slurries and dirty fluids, and use of one type of transmitter regardless of pipe size (see Figure 1). The limitations of

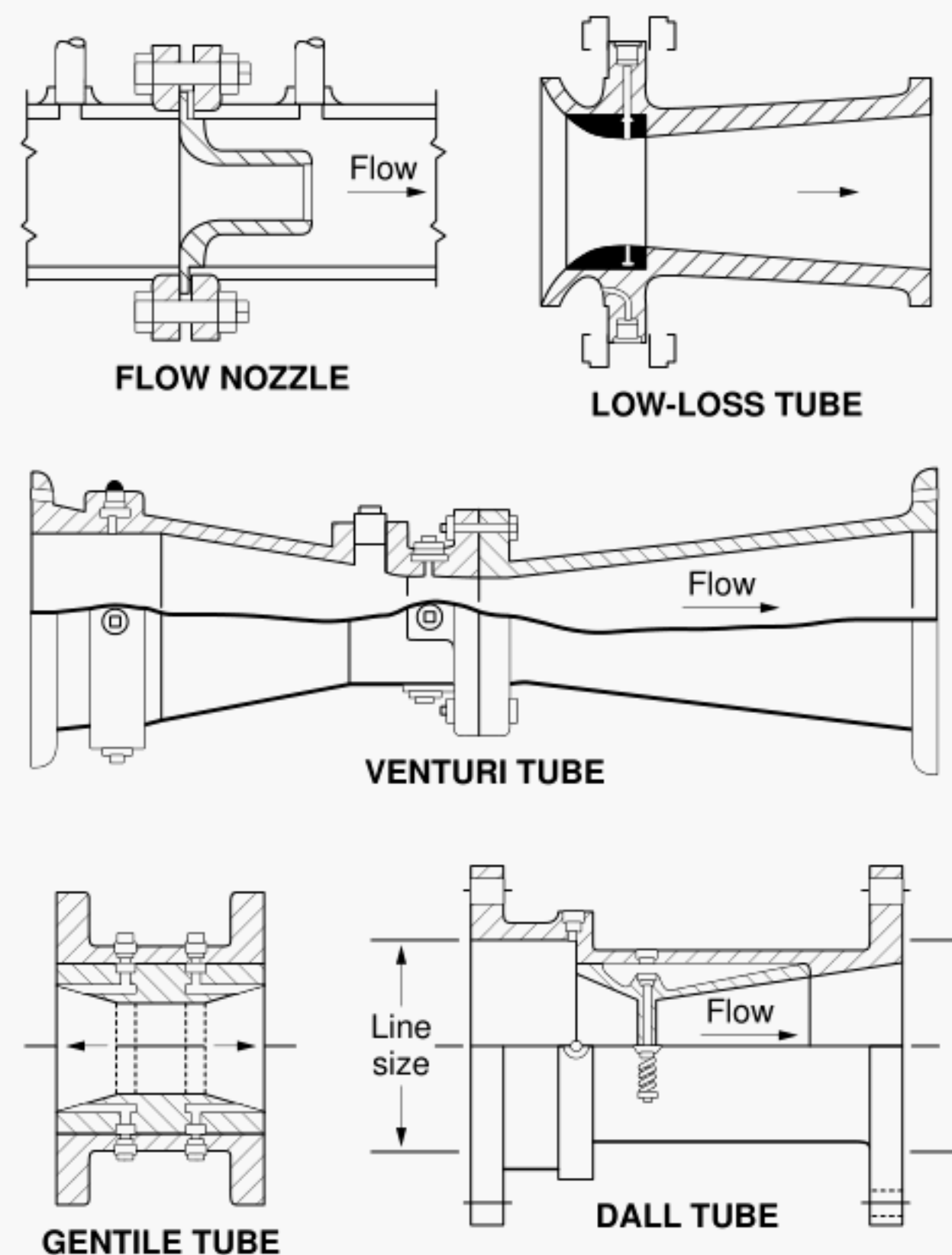


Figure 1—Flow Nozzle, Venturi Tube, and Flow Tubes

venturi and flow tubes include high cost (they are generally the most expensive differential-pressure producer) and the size and weight of the installation, which may require additional support. A straight run of upstream and downstream piping is required for a venturi or flow tube.

2.3.1.1.6 Pitot Tubes and Pitot Venturis

Pitot tubes and pitot venturis are used where minimum pressure drop is required and accuracy is not of prime concern. Advantages of pitot tubes and pitot venturis include very low cost, availability of averaging types, use of one type of transmitter regardless of pipe size, and ability to be added on stream with a hot tap. Limitations of pitot tubes and pitot venturis include their requirement for a low-range differential transmitter and their dependence on flow profile for accuracy. A pitot venturi requires a larger tap size, and installation requires special attention to clearances. A straight run of upstream and downstream piping is required for a pitot tube or pitot venturi (see Figure 2).

2.3.1.2 Differential Measuring Devices

2.3.1.2.1 General

Several types of measuring devices are used to determine the differential produced by the primary element. Flow is

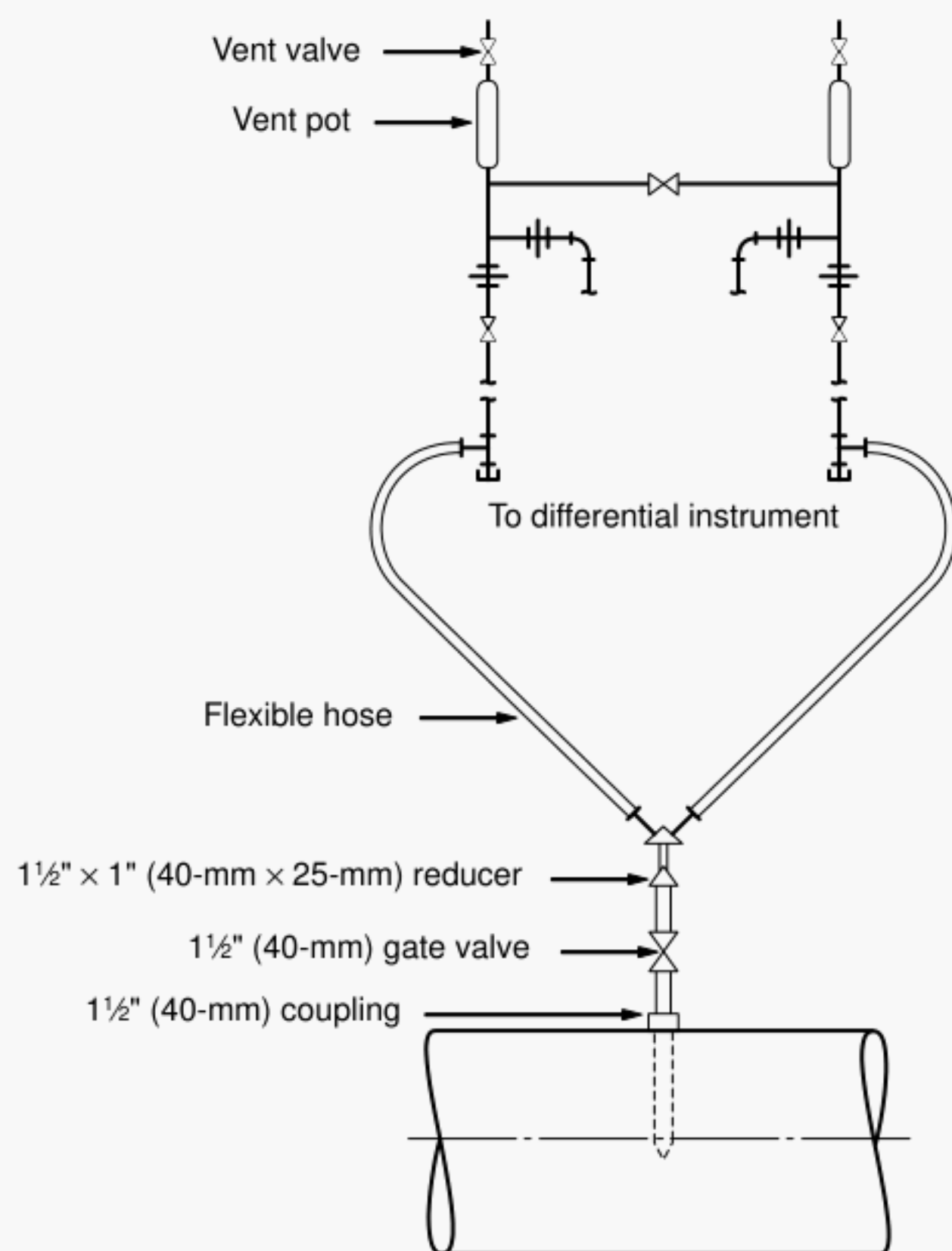


Figure 2—Pitot Tube Installation

proportional to the square root of the differential; therefore, to maintain accuracy at low flow readings, a range greater than 3:1 is not recommended. Multiple transmitters or microprocessor-based transmitters may be used to increase range. To calibrate the flow measuring or differential device, a manometer or precision test gauge should be used to read the differential input. The calibration devices should be graduated in the same units as the meter range (for example, inches of water). Pneumatic outputs may be read on the same type of device. Electronic devices require a precision voltmeter or ammeter. Total flow may be obtained by manually integrating the flow chart with a planimeter or by equipping the meter with an integrator. Corrections must be applied for changes in the condition of the flowing stream for deviation from original flow calculations. The most commonly used differential-pressure measurement devices are described in 2.3.1.2.2 and 2.3.1.2.3.

2.3.1.2.2 Diaphragm Transmitters

Differential-pressure transmitters of the diaphragm type are extensively used in refinery units. To provide overrange protection and dampening, the body or capsule of the transmitter is filled with liquid. The transmission signal may be either pneumatic or electronic. Because of their low displacement, these instruments can generally be used without a seal or condensate pot. Line mounting is preferred if the location is accessible and has minimum vibration. Gas meters are mounted above the line to allow any condensate to drain back. Liquid meters are mounted below the line to prevent gas or vapor from being trapped in the sensing lines, which could cause errors from unequal static heads.

2.3.1.2.3 Bellows Meters

In a bellows meter, the bellows is opposed by a calibrated spring system and is filled to prevent rupturing when the bellows is overpressured and to provide pulsation damping. Bellows meters can be line mounted or remotely mounted at grade or on platforms with adequate support. Seal chambers or condensate pots may be used; however, a 3/4-inch (20-millimeter) tee has sufficient volume to act as a liquid seal or condensate pot in steam or condensable-vapor service for instruments that displace less than 1 cubic inch (16.4 cubic centimeters) with full-scale deviation. If the displacement is greater than 1 cubic inch (16.4 cubic centimeters) or if the differential of the instrument is low compared with the column displacement, regular condensate pots should be used.

2.3.1.3 Installation

2.3.1.3.1 General

Installation of differential-pressure flow devices is generally the same regardless of the type of primary element and requires consideration of the factors described in 2.3.1.3.2 through 2.3.1.3.4.

2.3.1.3.2 Meter Location

Close-coupled mounting is preferred for transmitters. When close coupling is not available, the meter should be mounted at a convenient height of 4 or 5 feet (1.2 or 1.5 meters) above grade, platforms, walkways, or other permanent means of access.

2.3.1.3.3 Impulse Lines

Impulse lines for remote devices should be as short as possible, 3 feet for close-coupled transmitters and preferably not more than 20 feet (6 meters). For liquid measurement the lines should slope down at least 1 inch per foot from the orifice taps.

Meter piping should be designed and installed in accordance with the piping specification for the service involved. It is preferable to use Type 304 or better stainless steel tubing with a minimum outside diameter of $\frac{1}{2}$ inch (15 millimeters) for meter impulse leads. In special cases or where user preference dictates, $\frac{1}{2}$ -inch (15-millimeter) Schedule 80 or heavier pipe may be used.

All locally mounted instruments and impulse lines handling water or process fluids that may freeze, become excessively viscous, or form hydrates in cold weather should be installed in accordance with Section 6.

Meter-connecting piping and manifolding is a source of meter inaccuracy. It is possible to develop more liquid head in one meter lead line than the other because of differences in specific gravity, temperature, or the amount of gas or water in the lines. For example, if the meter is 100 inches (2.5 meters) below the orifice, with one side filled with water and the other side filled with a liquid that has a specific gravity of 0.65, the zero error will be 35 percent of full scale for a 100-inch (2.5-meter) range. Note that most hydrocarbon streams contain some water. Mounting the meter or transmitter close-coupled to the meter taps greatly reduces head error from differences in specific gravity or from vapor binding.

2.3.1.3.4 Meter Manifolds

Manifolds are recommended on all differential-pressure measuring devices for checking zero and for isolating the meter from its process service. Special manifold valves provide reliable, convenient, simplified installations and are commonly used alternatives to individual block-and-bypass-valve assemblies.

Valving for close-coupled transmitters requires process blocks at the orifice flange and an equalizing bypass valve at the meter. This can be accomplished by using conventional line-class valves, installed with rigid pipe nipples with male inlets that fit directly into the orifice flange taps, for the process blocks. Short impulse lines connect the valves to the special bypass manifold valve, which is mounted directly on the transmitter. These manifold valves can be adapted to fit most manufacturers' transmitters (see Figure 3).

At-grade or remote installations require additional considerations. Valving at the orifice flanges is the same as for close-coupled transmitters, but valving at the meter requires different configurations (see Figure 4).

Special process or maintenance considerations may require the addition of drain or blowdown valves, condensate drip legs, and vents. In some services it is necessary to protect meters from the process or to reduce potential errors caused by vapor condensation in the meter leads. In steam and condensable service, a means must be provided of maintaining an equal liquid head on each side of the meter (see Figure 5).

Additional requirements may include seals and purges. These are discussed later in this section.

2.3.2 VARIABLE-AREA METERS

2.3.2.1 General

Variable-area meters are available as indicators, transmitters, recorders, local controllers, totalizers, and many combinations of these, with or without alarms. They are often used as purge meters for the sensing elements of other instrumentation and process equipment.

Other typical uses include measurement of the following fluids:

- Liquefied petroleum gas or other volatile liquids.
- Liquids that require heat to prevent congealing or freezing. (Jacketed meters are available that use steam or another heating medium.)
- Slurries or streams with suspended solids. (The meter manufacturer should be consulted regarding application.)
- Acids.

Advantages of variable-area meters include wide flow range (for example, 10:1), linear transmitter output, and minimal effect of gas compressibility. Limitations of variable-area meters include their lack of availability in all materials; viscosity ceiling limits, which are provided by manufacturers and must be observed; their need to be installed vertically, which usually requires additional piping; the difficulty of checking calibration; the difficulty of changing range; the requirement for a minimum back pressure for gas applications; the fact that their magnetically coupled indicators or transmitters are subject to errors if metal particles accumulate; and the requirement for shutdown of process lines to take these meters out of service, unless blocks and bypass are provided.

2.3.2.2 Installation

A variable-area meter should be installed in a location that is free from vibration and has sufficient clearance for occasional float removal for service or inspection. The meter should be readable and readily accessible for operation and maintenance. In general, when a meter is to be used in reg-

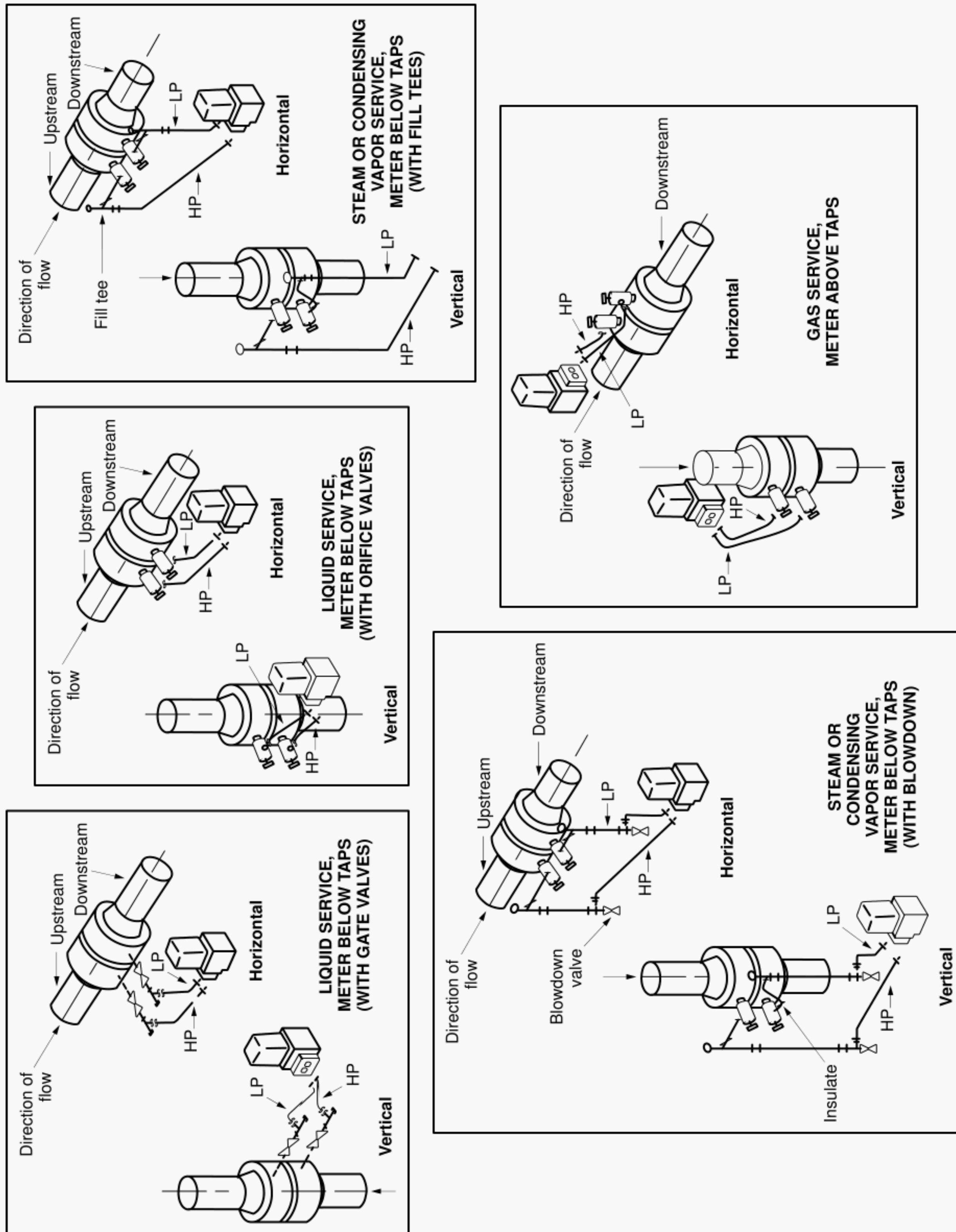


Figure 3—Close-Coupled Differential-Pressure Flowmeters

Notes to Figure 3:

1. Impulse leads should be kept to a minimum length.
2. A positive slope, at least 1:12 for all leads, should be provided. This will prevent pockets and provide positive venting or draining.
3. The high-pressure side of the instrument should be connected to the upstream tap.
4. For liquid service in vertical lines, upflow is preferred to prevent buildup of vapor or trash above the plate.
5. For liquid, steam, or condensable-vapor service, meters should be installed below the taps.
6. For gas service, meters should be installed above the taps.
7. For steam service, both fill tees (condensate pots) must be installed at the same centerline elevation as that of the upper tap.
8. Flowmeter installations for vena contracta or pipe tap connections are similar to those shown for flange taps.

ulating service, it should be placed as close as possible upstream of the throttling point.

Variable-area meters must always be mounted vertically, with the outlet connection at the top of the meter and the inlet connection at the bottom.

Most variable-area flow measurement is independent of upstream piping arrangements. Elbows, globe or throttling valves, and other fittings have essentially no effect on measurement accuracy if they are no closer than 5 pipe diameters upstream of the meter.

When vertical or horizontal connections are interchangeable, horizontal connections are recommended. Horizontal connections permit the use of the plugged vertical openings as convenient cleanout ports. The design of most variable-area meters permits the end fitting to be rotated in 90-degree increments. Piping connections for variable-area meters are shown in Figure 6. All piping should be properly supported, and care must be taken to avoid any strain on the meter body.

Block and bypass valves should be provided where operating conditions do not permit shutdown while the meter is being serviced. The bypass line and valves should be the same size as the meter. Block valves should be installed upstream and downstream of the variable-area meter. A drain valve should be provided. For a variable-area meter installation with a bypass, care must be taken to ensure that the bypass valve is tightly closed when the meter is in service.

Armored meters must be used to measure hydrocarbons.

2.3.3 MAGNETIC FLOWMETERS

2.3.3.1 General

A magnetic flowmeter measures the volumetric rate of flow of any liquid that has adequate electrical conductivity. Most petroleum hydrocarbons have insufficient conductivity to be measured with a magnetic flowmeter; therefore, use in petroleum industry applications is limited to certain water, acids, emulsions, and other conductive liquids. A magnetic flowmeter consists of two parts—a primary element, installed directly in the process line, and a secondary element, the electronic transmitter. The meter generates a signal proportional to the rate of flow.

Magnetic flowmeters are widely applied on slurries, since these meters are obstructionless, and on corrosive fluids, since only the liner and electrodes are in contact with the process stream. They are suitable for very viscous fluids or where negligible pressure drop is desired.

Magnetic flowmeters have the following advantages:

- a. Their accuracy is typically ± 0.5 percent of full scale. About 1–1½ percent of actual flow rate is attainable.
- b. They respond only to the velocity of the flow stream and are therefore independent of density, viscosity, and static pressure.
- c. They have rangeability of 10:1 or greater.
- d. They can be used to measure bidirectional flow.
- e. Fluid temperatures from -40°F to $+500^{\circ}\text{F}$ (-40°C to $+260^{\circ}\text{C}$) can be handled.
- f. Fluid pressures from full vacuum to 30,000 pounds per square inch (204 megapascals) can be handled.
- g. Pressure drop is negligible.
- h. A wide variety of sizes are available, from ½ inch (2.5 millimeters) upward.

Magnetic flowmeters are limited by the following characteristics:

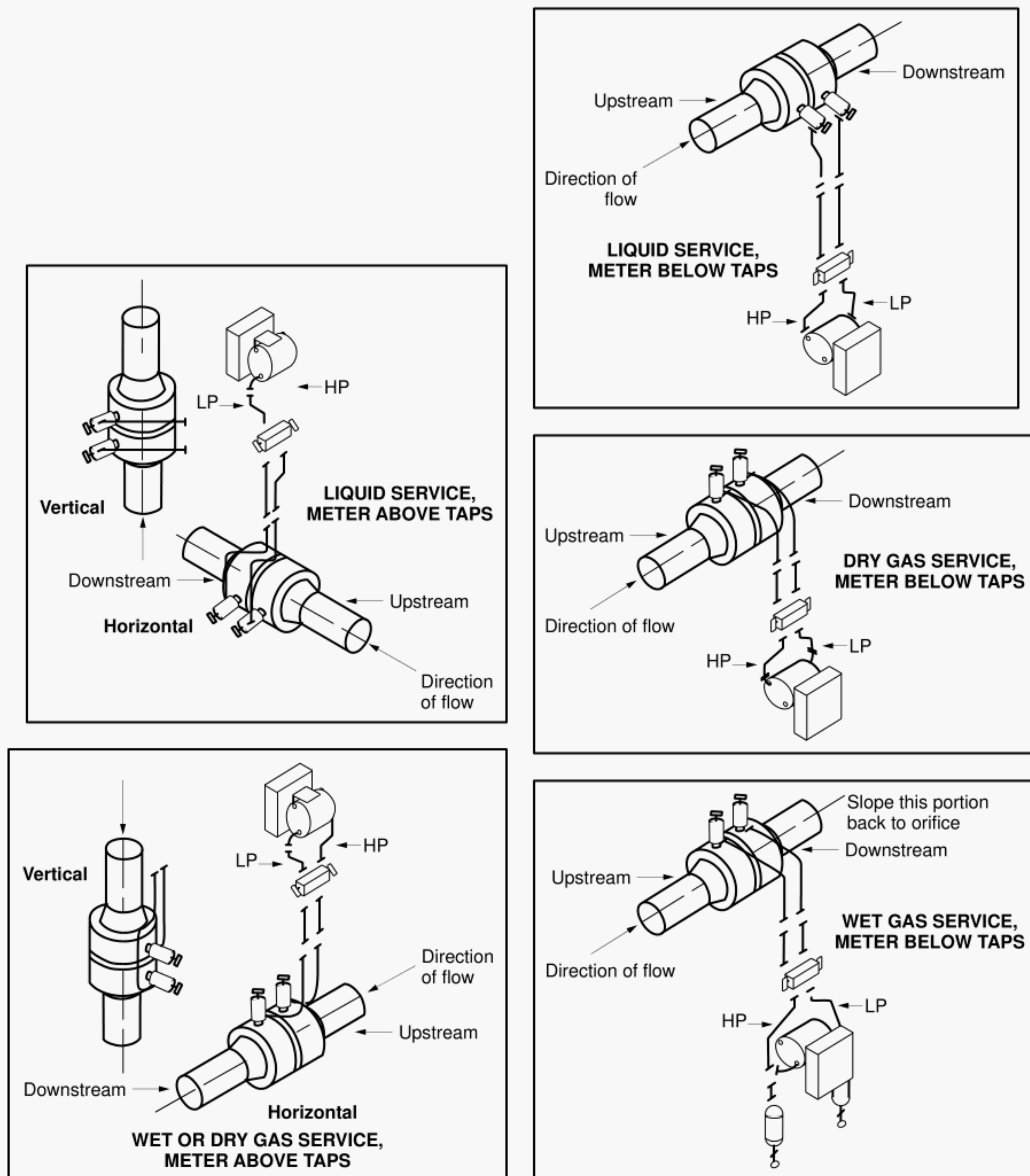
- a. The process fluid must generally have a conductivity greater than 2 micromhos per centimeter. (Special-conductivity units are available for fluids with a conductivity as low as 0.1 micromho per centimeter.)
- b. Special care is required for erosive application.
- c. They cannot be easily calibrated in place.
- d. Their cost is moderate to high.
- e. Large sizes are very heavy.

2.3.3.2 Installation

Considerable care must be exercised when the magnetic flowmeter's primary element is installed in the pipeline. Special care must be taken to prevent damage to the liner and to ensure that grounding requirements are met. The manufacturer's installation recommendations should be followed, including consideration of upstream and downstream piping requirements. The transmitter is built on a rugged piece of pipe, but it should be handled as a precision instrument.

The transmitter should be accessible from grade or from a platform with enough space around it to permit removal of at least the top housing if necessary. Sufficient access should be available for removal of any inspection plates.

The magnetic flow transmitter tube may be installed in any position (vertical, horizontal, or at an angle), but it must run full of liquid to ensure accurate measurement. If the tube is mounted vertically, flow should be from bottom to top to ensure that the pipe is full. If the tube is mounted horizontally, the electrode's axis should not be in a vertical plane. A small chain of bubbles moving along the top of the flow line can prevent the top electrode from contacting the liquid.

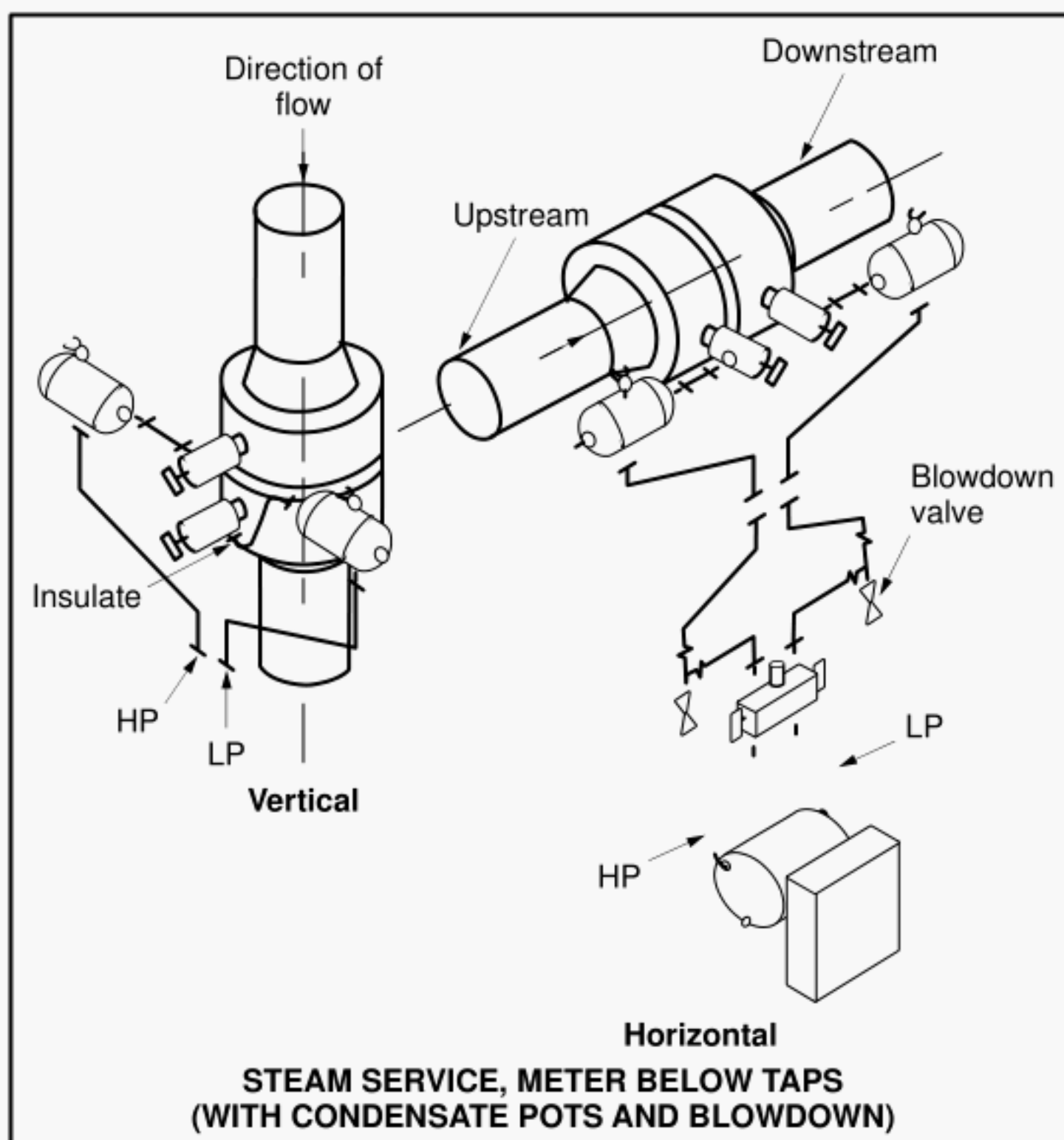
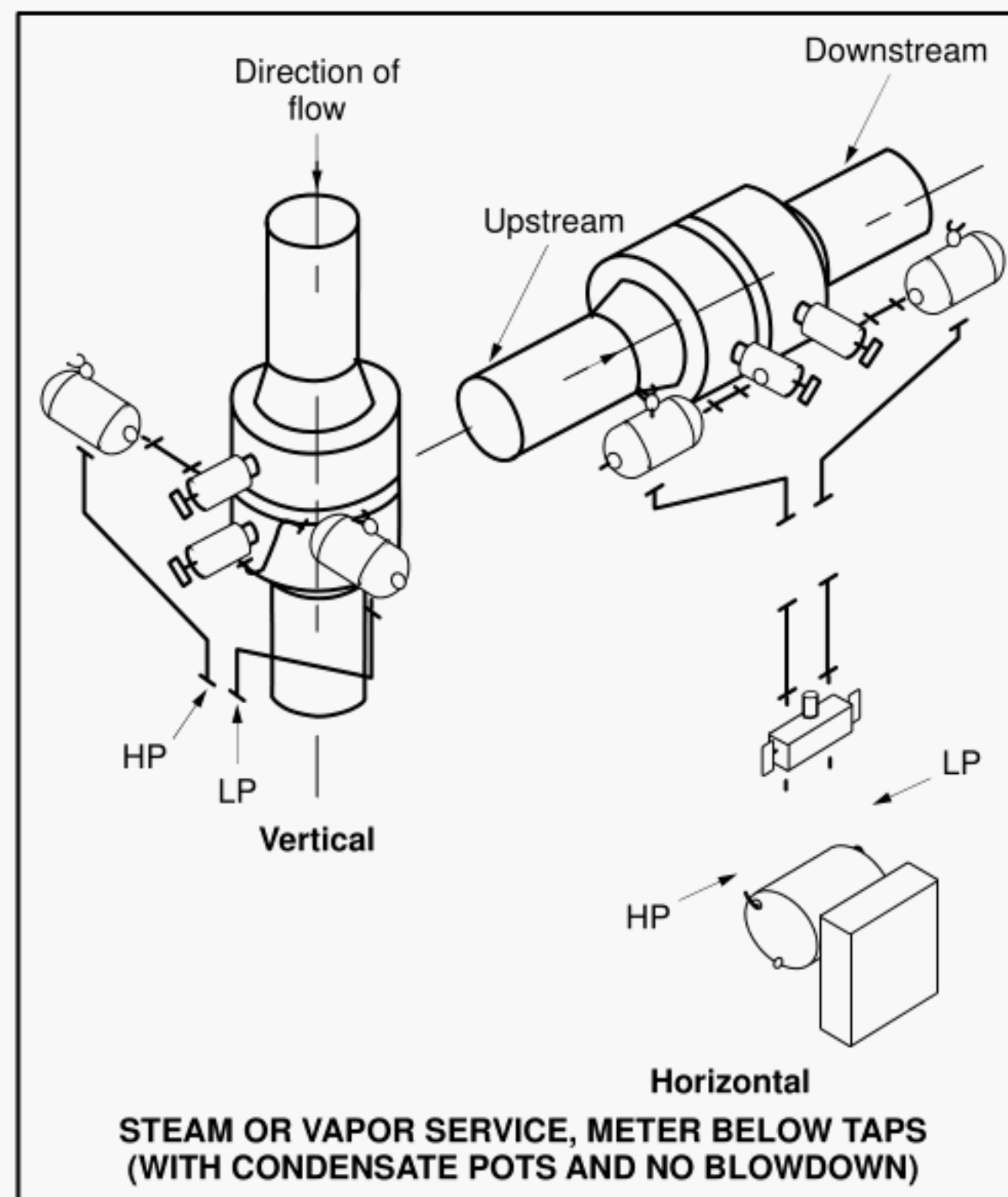


Notes:

1. Meter leads should be kept as short as possible (maximum of 20 feet).
2. For most instruments, when sealing is required, $\frac{3}{4}$ -inch fill tees usually provide enough condensate volume.
3. Secondary process block valves with equalizing bypass should be provided. Three- or five-valve manifolds may be used.
4. For liquid meters above an orifice, a seal leg should be provided below each tap.

5. For vapor meters above an orifice, a continuous slope back to the taps should be provided.
6. For dry gas meters below an orifice, drip pots are not required.
7. For wet gas meters below an orifice, the upper section of the impulse lead should be sloped back to the orifice, and suitably sized drip pots should be provided at lower meter connections.
8. Where redundant impulse line blocks are not required, a single-tube-fitting bypass valve may be used.

Figure 4—Remotely Mounted Differential-Pressure Flowmeters for Liquid and Gas Service



Notes:

1. In general, $\frac{3}{4}$ -inch tees provide condensate pots of sufficient capacity.
2. When required, blowdown connections should be provided above the three- or five-valve manifold block. Blowdown through the block or instrument may cause damage as a result of high temperature.
3. Tees or pots should be installed level with the upper tap.
4. Leads should be sloped 1:12 or more.
5. Vent valves are optional but highly desirable. Their vent port should be oriented away from the normal operator approach.
6. Where pots are installed above the meter to provide liquid seal for either steam or condensable vapor, the impulse leads should be insulated only between the orifice tap and the pot, except where winterizing is required.
7. Insulation is not required where the meter is above the orifice and the pots are installed at the taps, except where winterizing is required.
8. To provide the proper seal, leads must be connected to the appropriate bottom or end connections, as shown in the figure.
9. Where redundant impulse-line blocks are not required, a single-tube-fitting bypass valve may be used.

Figure 5—Remotely Mounted Differential-Pressure Flowmeters for Steam or Condensable-Vapor Service

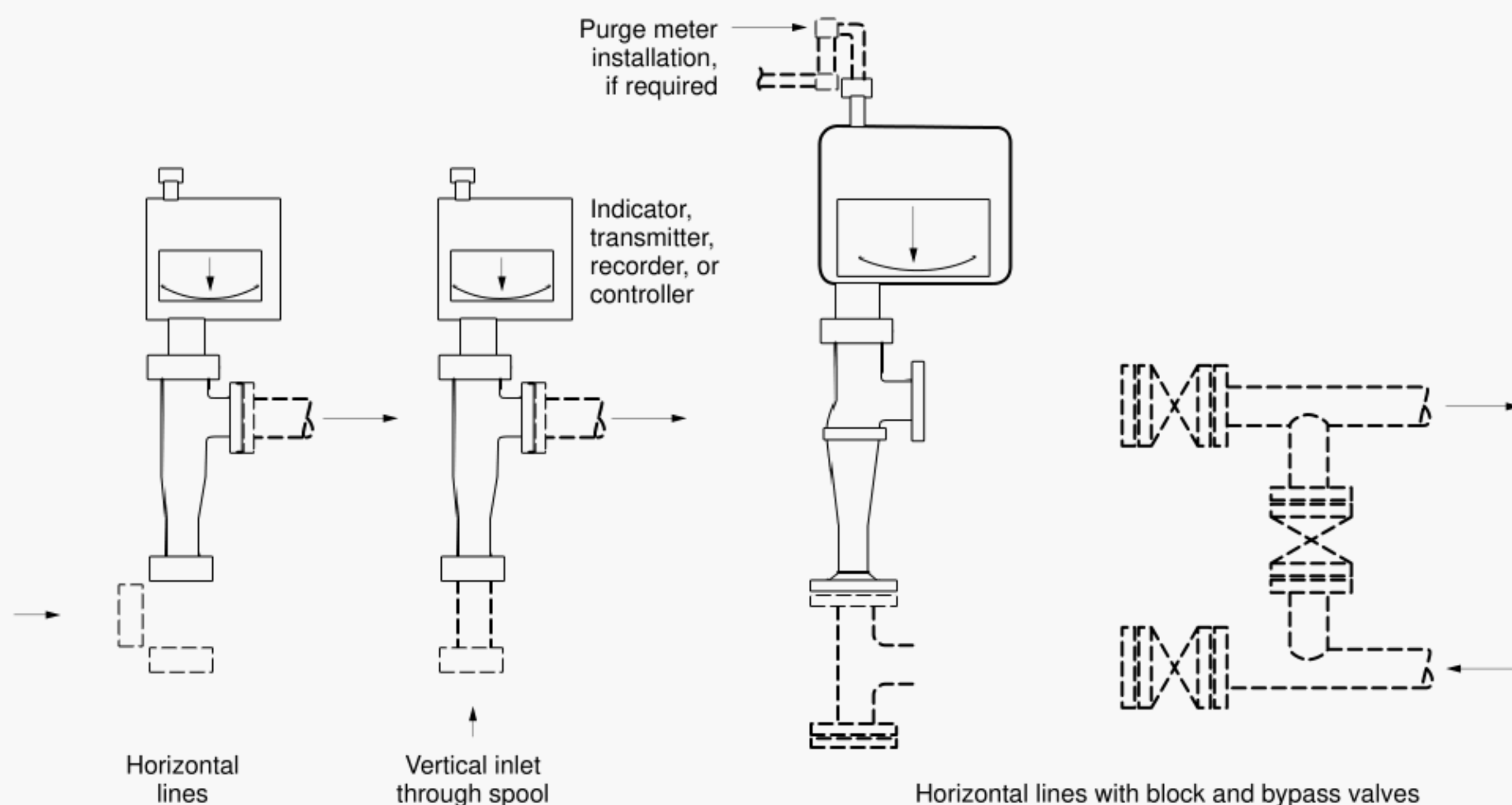


Figure 6—Variable-Area Meter Piping Configurations

Vertical mounting with a straight run on the inlet side and upward flow is recommended if an abrasive slurry is being measured. This arrangement distributes wear more evenly.

2.3.3.3 Electrical Installation

Power for magnetic flowmeters should be supplied at a voltage and frequency within the tolerance specified by the manufacturer.

Special low-capacitance cable is used to carry the generated signal from the primary element to the transmitter. The signal cable must not be installed close to the power cable or in the same conduit as the power supply. The manufacturer's recommendations should be observed.

The importance of proper grounding, which is necessary for personnel safety and satisfactory flow measurement, cannot be overemphasized. The manufacturer's instructions for grounding should be followed carefully. A continuous electrical contact to the same ground potential is necessary between the flowing liquid, the piping, and the magnetic flowmeter. This continuous contact is especially important if the conductivity of the liquid is low. How contact is achieved depends on the meter's construction and whether adjacent piping is unlined metal, lined metal, or nonmetallic. Jumpers from the meter body to the piping are always required. If the meter is installed in nonmetallic piping, it is always necessary to make a grounding connection to the liquid. This connection is achieved by means of a metallic grounding ring between the flanges, unless internal grounding has been provided in the transmitter. The grounding connection is ex-

tremely important and must be installed as recommended if the system is to operate properly.

Most magnetic flowmeters have their signal and power connections enclosed in splashproof or explosionproof housings. The connections must be sealed in accordance with the manufacturer's instructions and any applicable codes. Great care must be exercised in this area.

2.3.3.4 Start-Up and Calibration

No special procedures need be observed during start-up, since the magnetic flowmeter is obstructionless, but there are often electrical adjustments that must be made. The manufacturer's instructions should be consulted regarding these procedures.

2.3.4 TURBINE METERS

2.3.4.1 General

Turbine meters are used where their accuracy and rangeability are required. Their major application is for custody transfer and in-line product blending. The pulse outputs of turbine meters may be scaled for direct totalization in engineering units. Outputs from turbine meters are suitable for control or recording applications and are ideally suited for batch control applications. Compensation for nonlinearities due to viscosity is also available.

Turbine meters have the following advantages:

- Accuracy of 0.25 percent of rate with a repeatability of 0.10 percent or better is normal. (To obtain the highest accu-

racies, some form of meter proving is recommended.)

- b. Rangeability varies depending on meter design, fluid viscosity, density, and meter size.
- c. A high flow rate for a given line size is obtainable.
- d. Designs for very low flow rates are available.
- e. Turbine meters are available for a wide range of temperature and pressure ratings.
- f. Specially designed turbine meters are available for bidirectional flow.

Turbine meters are limited by the following characteristics:

- a. They are susceptible to wear or damage if the process stream is dirty or nonlubricating.
- b. They are susceptible to damage from overspeed and pulsing flow.
- c. They require maintenance and may require return to the manufacturer for recalibration after a bearing change or other maintenance.
- d. Their rangeability is affected by high viscosity and low density.
- e. Their cost is relatively high.
- f. They require strainers.
- g. Provers are required to maintain calibration accuracy.

2.3.4.2 Installation

2.3.4.2.1 General

Turbine meters are installed directly in the process line. The line should be relatively free from vibration. Meters with integrally mounted, direct-reading registers should be positioned so that they can be easily read and maintained.

Turbine meters are normally installed in horizontal lines but may be installed in vertical upflow lines. It is necessary to specify the position in which the meter is to be calibrated. Calibration for the installed position is required.

2.3.4.2.2 Piping

The accuracy and repeatability of measurements from turbine meters depend on the upstream and downstream piping. In addition to sufficiently long straight runs upstream and downstream, straightening vanes are required for high accuracy.

2.3.4.2.3 Bypass Piping

The need for bypass piping for turbine meters is determined by the application. It may be necessary to isolate or disassemble the meter for maintenance purposes. In continuous-service applications, where shutdown is considered undesirable, block and bypass valves must be provided to permit process operation while the meter is being serviced. Conditions that may necessitate disassembly of the meter include damage caused by foreign material, wear, or buildup

of solids. If the meter is bypassed, it should be in the main run, with the line-size block valves placed beyond the meter's required upstream and downstream piping runs. The bypass valves must be capable of positive shutoff to prevent measurement errors. The bypass piping installation should be free draining.

Bypasses are not permitted for custody transfer applications.

2.3.4.2.4 Strainers

All turbine meter installations should have strainers to prevent damage to the meter rotor. The strainer must be capable of removing particles of a size that might damage the rotor and bearings. The strainer should be located upstream of the required meter run.

2.3.4.3 Electrical Installation

The signal from a turbine meter is a low-level pulse, which makes it especially susceptible to noise pickup. Shielding of signal wires is recommended to eliminate spurious counts. If the transmission distance is more than 10 feet (3 meters), a preamplifier is recommended. The manufacturer's instructions should be consulted for details.

2.3.4.4 Start-Up and Calibration

Care must be taken to prevent damage to the turbine meter at initial start-up. The meter should be placed in service only after the process line has been flushed and hydrostatically tested. If strainers are used, they should be cleaned after flushing and periodically during operation. Flow should be introduced slowly to the meter to prevent damage to the impeller blades as a result of sudden hydraulic impact or overspeed.

The calibration factor, expressed in electrical pulses generated per unit volume of throughput, is normally called a K (meter) factor. The K factor depends on fluid conditions, is determined when the flowmeter is calibrated, and is inherent for the particular meter rotor. K factors of meter rotors vary within the same meter body size. No field adjustment may be made to the primary sensor.

2.3.5 POSITIVE-DISPLACEMENT METERS

2.3.5.1 General

The basic types of positive-displacement meters are nutating disk, oscillating piston, fluted rotor, rotary (lobed impeller and sliding vane), and oval-shaped gear.

Positive-displacement meters measure flow by mechanically trapping successive volumetric segments of the liquid passing through the meter. The number of segments is converted to shaft rotation. A gear train and calibrator convert shaft rotation to the appropriate volumetric units.

Temperature compensators are available to correct the output as the fluid temperature changes. Pulse generators are available to provide pulse outputs for meter proving or remote readout.

Positive-displacement meters are used because of their excellent repeatability over wide flow ranges. They are used for heavy or viscous fluids in custody transfer and product-blending applications.

Positive-displacement meters have the following advantages:

- a. Attainable accuracies are 0.05–0.15 percent of actual flow. Ensuring high accuracy requires some form of meter proving. Typical repeatabilities are 0.02–0.05 percent.
- b. Rangeability is normally 10:1. Positive displacement meters have excellent rangeability and accuracy, particularly with heavy or viscous fluids.
- c. Positive-displacement meters come in a range of sizes.

Positive-displacement meters have the following disadvantages:

- a. They are subject to mechanical wear.
- b. They are not interchangeable and must be supplied to match the service.
- c. They require filter/strainers.
- d. Their installation requires special considerations.

2.3.5.2 Installation

Positive-displacement meters are installed directly in the process piping and can be a source of vibration. Adequate foundations should be provided (refer to the manufacturer's recommendations).

Positive-displacement meters are normally installed in horizontal lines. Certain types are specifically designed for vertical lines. Meters should be installed so that the meter case or body is not subject to piping strain. The piping should be arranged so that the meter is always full of liquid. Adequate back pressure may be required to eliminate the possibility of vapor release.

For continuous process services, a bypass around a positive-displacement meter is recommended. For custody transfer, bypasses are not permitted. Positive-displacement meters should always be installed with an adequate strainer to prevent foreign matter from damaging the meter or causing excessive wear; the manufacturer's recommendation on mesh size should be observed. Where excessive amounts of debris are entrained in the fluid, strainer pressure drop should be monitored.

The installation of a positive-displacement meter should be designed to avoid air or vapor in the piping. Where the design does not allow for this, air eliminators should be considered. Air eliminators can leak or have inadequate capacity to protect the meter from slugs of air or vapor; such eliminators should be removed and replaced.

2.3.5.3 Start-Up and Calibration

Positive-displacement meters can be damaged or destroyed during initial start-up. The manufacturer's instructions, as well as the following general guidelines, should be followed during start-up:

- a. Positive-displacement meters and air eliminators should be installed in the line only after the piping has been flushed and hydrostatically tested.
- b. The meter and strainer basket should be installed after the piping has been flushed.
- c. Strainer pressure drop should be monitored, and strainers should be cleansed as required.
- d. Extreme care must be taken to vent air from the piping. Flow should be introduced slowly to prevent hydraulic shock.
- e. Custody transfer meters must be proved initially and at regular intervals.

Piping for custody transfer service should be designed to allow for easy proving and maintenance of meters.

2.3.6 VORTEX METERS

2.3.6.1 General

A vortex train is generated when a bluff-body obstruction is placed in a liquid or gas stream. This train of high- and low-pressure areas can be measured by sensors on the body or the pipe wall. The frequency of pressure changes is linear to the velocity of the fluid stream. Since flow in any pipeline is a function of cross-sectional area and velocity, a direct relationship exists between frequency and flow rate. Vortex meters are used in applications that require wide rangeability and accuracy.

Vortex meters are commonly used in the following services:

- a. Steam.
- b. Cooling water.
- c. Process water.
- d. Light hydrocarbons where large turndown is required.
- e. Gas flow where large turndown is required.

Vortex meters have the following characteristics:

- a. Wide rangeability (for Reynolds numbers above 10,000).
- b. An accuracy of 1 percent of rate.
- c. A wide range of sizes.
- d. Linear output.
- e. Availability of pulse and analog outputs.

Vortex meters have the following limitations:

- a. A limited range of construction materials is available.
- b. Vortex meters are generally not suitable for slurries or high-viscosity liquids.
- c. Users cannot check calibration.

- d. Turbulent flow is required.
- e. Vortex meters have overrange limitations.
- f. Strainers may be required.
- g. Vortex meters are affected by pulsating flow.

2.3.6.2 Installation

Vortex meters are installed directly in the process piping and are normally supported by the piping. They may be installed in any orientation. A vortex meter should be installed so that the meter body is not subjected to piping strain. In liquid applications, the piping should be arranged so that the meter is kept full.

Block and bypass valves should be provided when operating conditions do not permit shutdown.

2.3.6.3 Start-Up and Calibration

Vortex meters are sometimes damaged during start-up of new installations as a result of debris in the line. The line should be flushed and hydrostatically tested before the meter is installed.

Since velocity profile is critical, it is imperative that gas-kets not protrude into the flow stream when flanged meters are installed.

Field calibration of vortex meters is limited to electrically spanning the converter or, on a pulse-output type, adjusting the scaling factor.

2.3.7 MASS FLOWMETERS

2.3.7.1 General

Mass flowmeters are of two basic types and have limited use in the refining industry. The installation and use of these instruments should closely follow the manufacturer's recommendations. This section is intended to summarize the features and philosophy of these devices.

2.3.7.2 Mass Flowmeter—Coriolis

Coriolis mass flowmeters measure mass units directly. Fluid flow through a tube vibrating at its natural frequency produces a coriolis force. The resulting tube deflections are measured and signaled proportionally to generated mass flow.

A Coriolis meter can be used with liquids, including liquids with limited amounts of entrained gas, and slurries. A Coriolis meter can also be used with dry gases and superheated steam if the fluid's density is high enough to operate the unit properly.

Although Coriolis meters are nonintrusive, in some designs the flow path through the meter is circuitous. In addition, the flow is generally separated into two tubes that are much smaller in cross-sectional area than is the inlet process piping. For this reason, it is relatively easy for any secondary phase to build up in a meter that has not been carefully installed. The pressure loss can be substantially higher than that in other types of nonintrusive elements, and cavitation and flashing can be problems with volatile fluids.

Start-up problems with Coriolis meters are typically due to improper installation. Installation should be strictly in accordance with the manufacturer's recommendations. Pressure containment enclosures are available when required. These meters are not affected by distortion of the velocity profile and do not require metering runs.

Although Coriolis meters generally cost much more than other types, they measure mass flow rate without the need for additional elements. The applications for these meters have been limited to difficult fluids or applications in which their accuracy justifies the higher cost (such as in billing, custody transfer, and batching and blending services).

2.3.7.3 Mass Flowmeter—Thermal

Thermal mass flowmeters are generally of two types—those that measure the rate of heat loss to a stream from a heated body, and those that measure the temperature rise of a stream as it passes over or through a hot body. Mass flow is inferred from the fluid's physical properties, such as thermal conductivity and specific heat, which are independent (within limits) of temperature and pressure.

In one design, a heat source raises the temperature of the fluid as it passes through a meter detector channel that contains three thermistor beads mounted in a line parallel to the flow. The center thermistor is heated by a current source, and the other two are placed an equal distance upstream and downstream from it. Voltages developed across the two outside thermistors, as a result of heat transfer into the fluid, generate the mass flow measurement. Dirt in the flow stream can clog the detector channel, which has a smaller diameter than does the bypass channel that handles most of the flow.

In another type of thermal meter, an immersed sensing element is heated to a constant temperature higher than that of the fluid stream, and a sensor responds to the cooling effect of fluid molecules passing by. An ambient temperature sensor, an integral part of the mass flow circuit, compensates the circuit over a wide range of process temperatures. These meters must be calibrated for the specific fluid, because the inferred flow rate is related to several of the fluid's properties.

SECTION 3—LEVEL

3.1 Scope

This section discusses recommended practices for the installation and general application of the more commonly used instruments and devices for indicating, recording, and controlling the liquid and solid levels and liquid–liquid interface levels normally encountered in petroleum refinery processes.

A wide variety of level instrumentation is currently available. Selection and proper installation depends on a number of variables, such as (a) the type of vessel, fluid, or material involved (namely, solids, granules, liquids, or a liquid–liquid or liquid–foam interface), (b) process conditions (namely, pressure, temperature, specific gravity, boiling point, viscosity, and pour point), (c) what the instrument is to accomplish (monitoring, on–off or modulating control, or alarm), and (d) whether the signal is to be electronic or pneumatic.

Six types of instruments are covered:

- a. Locally mounted indicating gauges (see 3.3), including tubular gauge glasses, armored gauge glasses, and magnetic gauges.
- b. Level transmitters (see 3.4), including displacement, differential-pressure, hydrostatic-head, nuclear, ultrasonic, and capacitance/radio-frequency types.
- c. Locally mounted controllers (see 3.5), including displacement, ball-float, and differential-pressure types.
- d. Level switches (see 3.6).
- e. Tank gauges (see 3.7).
- f. Accessories (see 3.8), including seals, purges, and weather protection.

3.2 General

3.2.1 INTRODUCTION

Certain general procedures, practices, and precautions apply to practically all of the instruments discussed in this section. Where applicable, the material discussed in 3.2.2 through 3.2.9 should be considered a part of each of the subsequent discussions.

3.2.2 ACCESSIBILITY

All locally mounted liquid level instruments, including gauge glasses, should be readily accessible from grade, platforms, fixed walkways, or fixed ladders. For maintenance purposes, rolling platforms are frequently used when free access is available in the area below the instruments.

For general service, externally mounted level devices are preferred, since they permit access for calibration and maintenance. Internally mounted devices are therefore usually limited to services in which external devices cannot be used

or to services in which a shutdown for maintenance is acceptable.

3.2.3 READABILITY

In all applications in which a liquid level is regulated by a control valve, some indication of the level—a gauge glass, receiver pressure gauges, or another indicator—should be clearly readable from the control-valve location to permit manual control when necessary. Such level indication at the valve is not necessary if the control system cannot be operated manually from the control-valve station.

Level-indicating instruments should be located on vessels so that the instruments are visible from operating aisles.

3.2.4 CONNECTIONS TO VESSELS

Level-instrument connections must be made directly to vessels and not to process flow lines or nozzles (continuous or intermittent) unless the fluid velocity in the line is less than 2 feet (0.6 meter) per second.

Connections and interconnecting piping should be installed so that no pockets or traps can occur. Where pockets are unavoidable, drain valves should be provided at low points. The minimum recommended size for drain valves is $\frac{3}{4}$ inch.

3.2.5 MULTIPLE-INSTRUMENT MOUNTING

When two or more instruments, including gauge glasses, are required for any application (such as a gauge glass and controller or a gauge glass and alarm switch), the instruments should be mounted so that the number of openings in the vessel is kept to a minimum. Suggested methods are covered in 3.3.3.3 and 3.4.2.3.

Block valves are generally used between a vessel nozzle and a standpipe.

3.2.6 BLOCK VALVES

3.2.6.1 Material

The materials of construction, rating, and type of connections for block valves must conform to the specifications for the equipment to which the valves are connected. This applies to all block valves, whether installed directly on the equipment or on a standpipe that is connected to the equipment.

3.2.6.2 Location and Size

Block valves may be located at the vessel connection or on a standpipe so that each instrument can be isolated. When valves are connected to standpipes, connections should be at

least $\frac{3}{4}$ inch in size. When the vessel connection is a flanged nozzle and the block valve is mounted directly on the nozzle, the connection should be at least 1 inch in size. When the vessel connection is a coupling and the block valve is mounted to a nipple, the connection should be at least $\frac{3}{4}$ inch in size. Fittings or piping between the vessel and block valves should be minimized.

3.2.7 STRAIN RELIEF

Connections between vessels and heavy gauges, controllers, or transmitters should be relieved of strain by properly supporting such instruments (and seal pots, where used) and by installing offsets or expansion loops where necessary to compensate for thermal expansion differences.

3.2.8 VIBRATION

Some level instruments are susceptible to damage or malfunction if they are subjected to vibration. To minimize vibration effects, such instruments should be mounted on a rigid support adjacent but not connected to the source of vibration. Such an arrangement requires flexible tubing or conduit connections between the source of vibration and the instrument. Additionally, shockproof mounts may be considered. Instruments should be carefully selected, since some instruments are less susceptible to vibration effects.

3.2.9 DRAINS AND VENTS

Drain valves $\frac{3}{4}$ inch in size should be installed on the bottom connection to level instruments. In hazardous services, drains and toxic-vapor vents should be piped away from the instruments to a safe disposal area. Vent valves are not generally necessary but may be installed when desired. Plugged vent connections should be provided on all installations where vent valves are not provided. Requirements established by the U.S. Environmental Protection Agency must be addressed.

3.3 Locally Mounted Indicating Gauges

3.3.1 GENERAL

Locally mounted indicating devices include armored gauge glasses, magnetic gauges, and differential-pressure level indicators.

3.3.2 TUBULAR GAUGE GLASSES

Tubular gauge glasses are not recommended for process units.

3.3.3 ARMORED GAUGE GLASSES

3.3.3.1 Application

The most commonly used types of armored gauge glasses (often called "flatglass") are transparent (through-vision) and

reflex gauges. Magnetic gauges are available for special applications or high-pressure service (see 3.3.4).

Transparent gauges should be used in installations involving acid, caustic, or dirty (or dark-colored) liquids; in high-pressure steam applications; for liquid-liquid interface service; and in any application where it is necessary to illuminate the glass from the rear. Illuminators made for the purpose and suitable for the service conditions should be purchased and installed in accordance with applicable codes and the manufacturer's recommendations.

Reflex gauges should be used in all other clean services, including C_4 and heavier hydrocarbons. They may also be used on C_3 and lighter hydrocarbons provided the product does not dissolve the paint or other coating on the inside of the gauge, thereby leaving a bare metal backwall which in turn reduces the effectiveness of the prisms.

For in-service applications involving liquids that may boil, large-chamber reflex or transparent gauge glasses are used. These gauges are designed to indicate the level of liquids that boil or tend to surge in the gauge.

3.3.3.2 Gauge Assemblies

Multiple single-section gauge glasses are used to make longer glasses. Recommended vessel connections are shown in Figure 7. The connections are normally limited to four sections or 5 feet between the connections. Longer glasses are often used for noncritical applications at temperatures below 400°F (200°C). At temperatures above 400°F (200°C), some companies limit length to three sections. Many companies limit applications to a pressure of 900 pounds per square inch. Additional support may be required when four or more sections are used. Offsets or expansion loops may be required to compensate for temperature expansion and contraction.

3.3.3.3 Multiple-Gauge Mounting

Wide level ranges are preferably observed by means of overlapping gauge glasses. Gauge cocks $\frac{3}{4}$ inch in size are generally used on multiple gauges. Where the vessel connection is a flanged nozzle and the block valve is mounted directly on the nozzle, the minimum size should be 1 inch. Many refiners have found that the maintenance required on the ball checks of automatic gauge cocks is so great that the use of individual block valves and pipe tees is preferable. Both types of installations are shown in Figure 7.

When breakage of a gauge glass could cause a hazardous condition (that is, when the vessel contains light ends or toxic liquids), excess-flow valves should be installed between the vessel and the gauge glass. Company standards may restrict use of "glass" gauge glasses for C_3 and C_4 service. If the glass is fractured during fire-fighting efforts, the broken gauge glass would constitute a potential secondary fuel source.

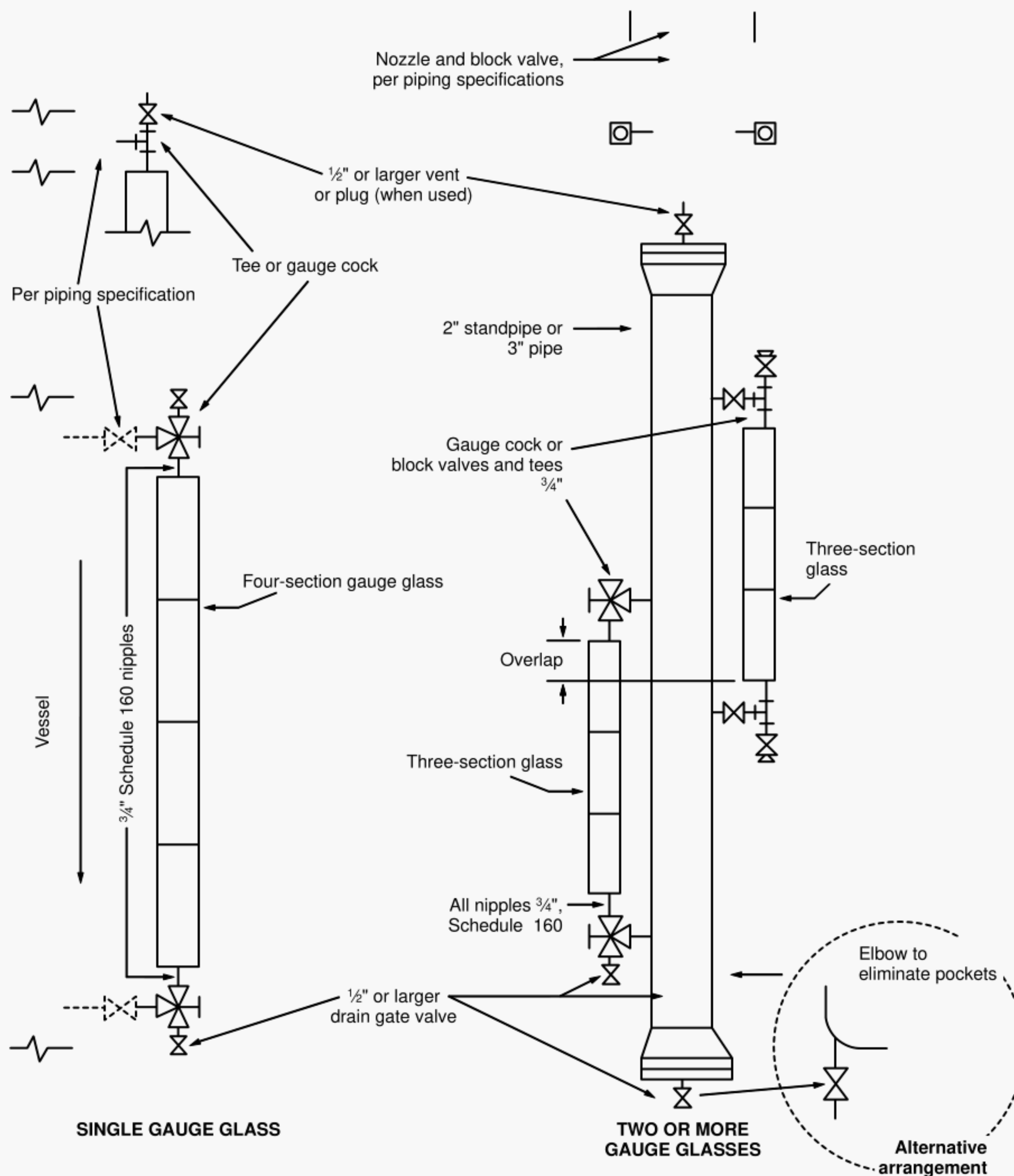


Figure 7—Gauge-Glass Assemblies

Interface observation requires the use of transparent gauge glasses. Figure 8 shows two commonly used and recommended methods of mounting multiple gauges on horizontal vessels where both liquid–liquid and liquid–vapor interfaces are to be observed. Connections to the vessel must be arranged so that there is always one in each phase of each interface being measured.

3.3.3.4 Protection of Gauge Glasses

Gauge glasses can be attacked (etched) by both vapor and liquids, for example, steam at a pressure of 250 pounds per square inch (1675 kilopascals), hydrofluoric acid, amines, caustics. In these cases, a thin protective film is recommended on the inside of the glass. Sunlight discolors some

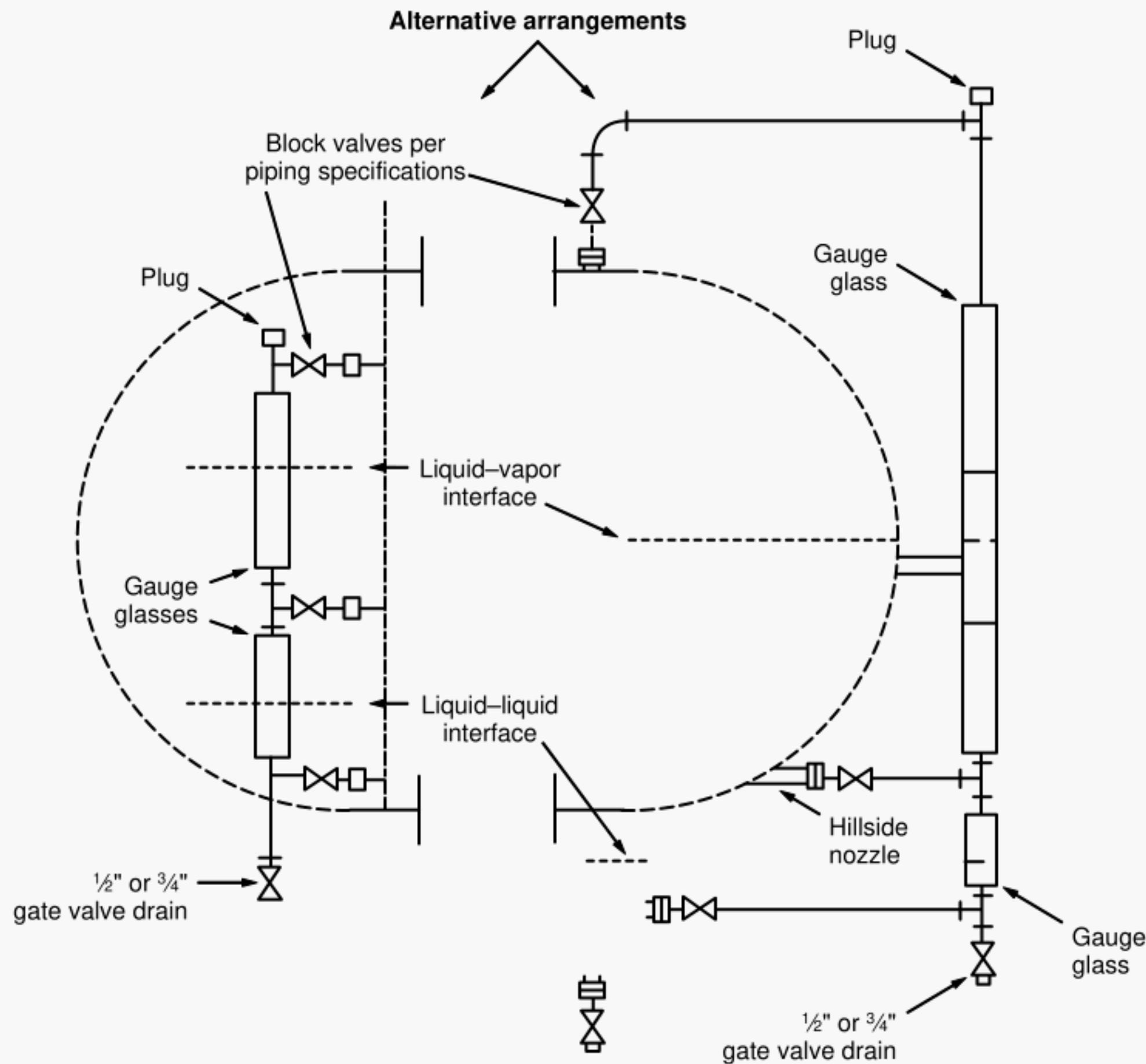


Figure 8—Gauge-Glass Mounting Arrangements for Horizontal Vessels and for Interface Measurement

plastics, so this should be considered when the film is selected. Such shields cannot be used in reflex gauges because they render prisms ineffective.

3.3.4 MAGNETIC GAUGES

3.3.4.1 Application

Magnetic gauges are used to gauge liquids (a) where glass failure is likely to occur due to fluids being handled, and (b) where the release of toxic gases, flammable liquids, and so forth is to be avoided. Typical construction consists of a float inside a sealed nonmagnetic chamber, and an indicator mounted outside the chamber, actuated or coupled magnetically to indicate level. Mounting to the vessel is usually accomplished by means of flanged connections and valves, similar to the mounting of flanged external displacement units (see Figure 9).

3.3.4.2 Precautions

Magnetic gauges must not be used in areas where forces or matter will affect the magnetic fields. This includes areas

that contain items such as steel support straps, heater wires, and steam-tracing tubing.

3.4 Level Transmitters

3.4.1 GENERAL

Level transmitters include pneumatic and electrical output systems that use a wide variety of measurement principles, including displacement, differential pressure, nuclear radiation, ultrasound, and capacitance/radio frequency.

Transmitters or transducers for electronic instruments should not be located too close to hot lines, vessels, or other equipment. Locations where ambient temperatures exceed the manufacturer's specified limit should be avoided, since placement of transmitters in such locations is likely to result in calibration difficulties and rapid deterioration of electronic components. The susceptibility of mechanical or electronic components to vibration should be ascertained, and where necessary, adjustments should be made in the mounting to minimize vibration.

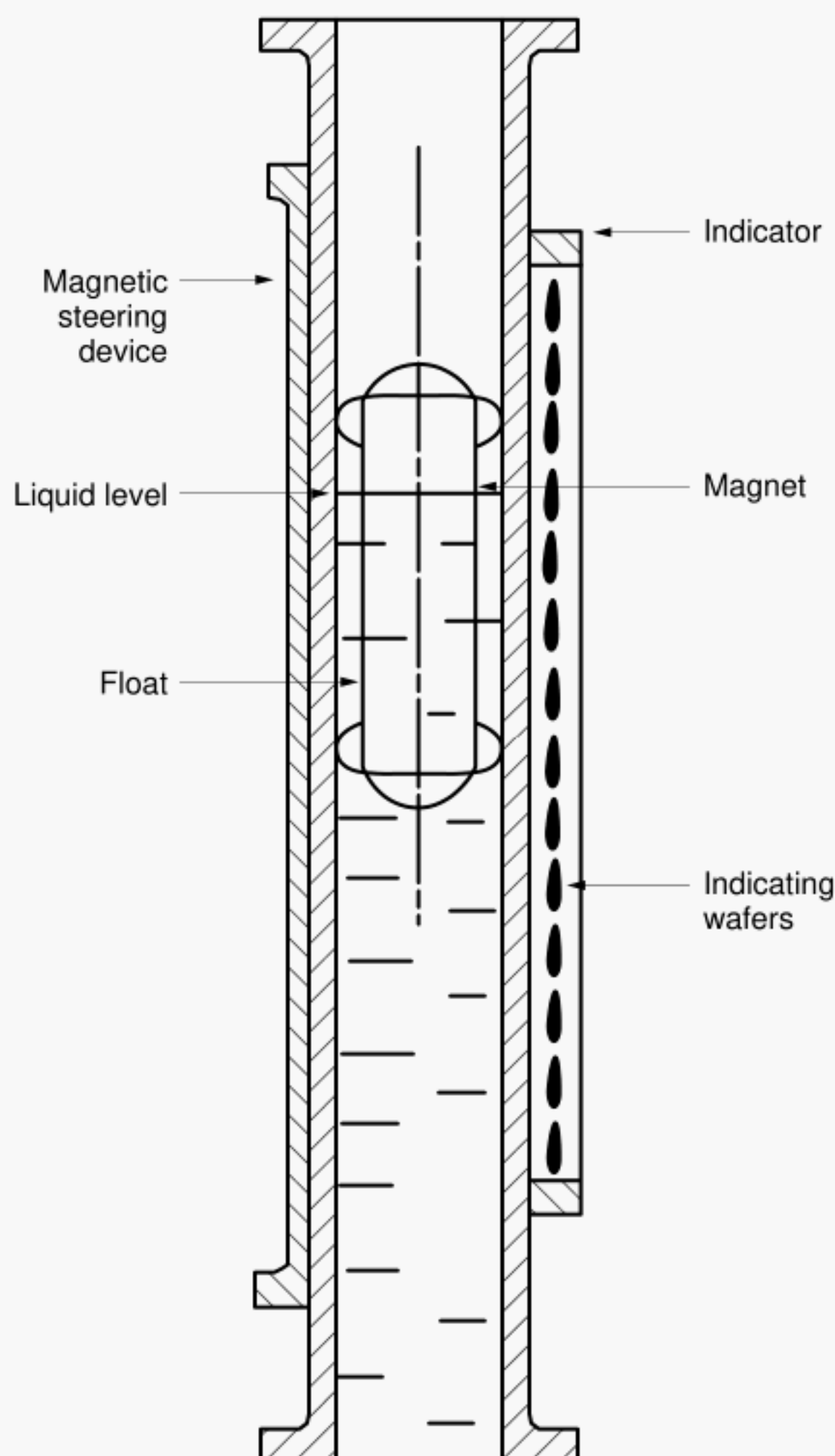


Figure 9—Typical Magnetic Gauge

Because of the speed of response of electronic level transmitters, caution should be exercised where level surges may be encountered; transmitters in such locations should be provided with damping.

3.4.2 DISPLACEMENT TRANSMITTERS

3.4.2.1 General

Displacement transmitters may be either blind or provided with a receiver-type local indicator on the output signal. Some pneumatic units are equipped with dual pilots, one, with a fixed band, for level transmission and the other for local level control.

3.4.2.2 Applications

Because the displacer itself has relatively little motion, it should be used with caution; for example, highly viscous material can cling to the displacer and affect its calibration.

When a displacement transmitter is used in such service, a liquid purge or heat tracing should be considered.

Caution should also be used in the application of displacement transmitters in services where hydraulic resonance⁵ may occur or where violent boiling occurs at the liquid surface.

Displacement transmitters are rarely used for vacuum service or service with volatile liquids.

Displacement transmitters in temperature services below 0°F (−18°C) or above approximately 400°F (200°C) should be provided with a means of isolating the transmitter mechanism from the process temperature to prevent malfunction.

If the liquid in the vessel is at a high temperature, and the temperature of the external cage is lower, the reading from the displacer will be in error as a result of the difference in density. Compensation for the temperature difference may be provided on installation, but if the difference changes, an error will be introduced.

3.4.2.3 Mounting of External-Cage Displacement Transmitters on Vessels

For installations of external-cage displacement transmitters, connections to vessels should be made by means of nozzles, block valves, and pipe fittings selected for the service (see Figures 10, 11, and 12).

Transmitter and controller installations should be provided with gauge glasses in parallel. A separate set of taps for independent level indication is normally recommended.

3.4.2.4 Connections to Vessels

In most process applications, level transmitters and controllers should have 1½- or 2-inch flanged connections.

Drain gate valves ¾ inch or larger in size should always be provided, and if one or more vents are required or desired, they should be gate valves ¾ inch or larger in size, installed as indicated in Figure 11.

3.4.2.5 Installation of External-Cage Displacement Unit and Standpipe

For wide level ranges or where it is desirable to minimize vessel connections, a standpipe and overlapping gauge glasses can be used, as shown in Figure 12. The standpipe, usually of 2- or 3-inch pipe, serves as a mechanical support for the instruments and as a surge chamber to prevent turbulence or foam from interfering with the operation of the transmitter. On horizontal vessels where standpipes are used with a wide level range or where multiple instruments of considerable weight are used, it is often necessary to provide additional support.

⁵F. G. Shinskey, *Process Control Systems*, "Hydraulic Resonance," McGraw-Hill, New York, 1989.

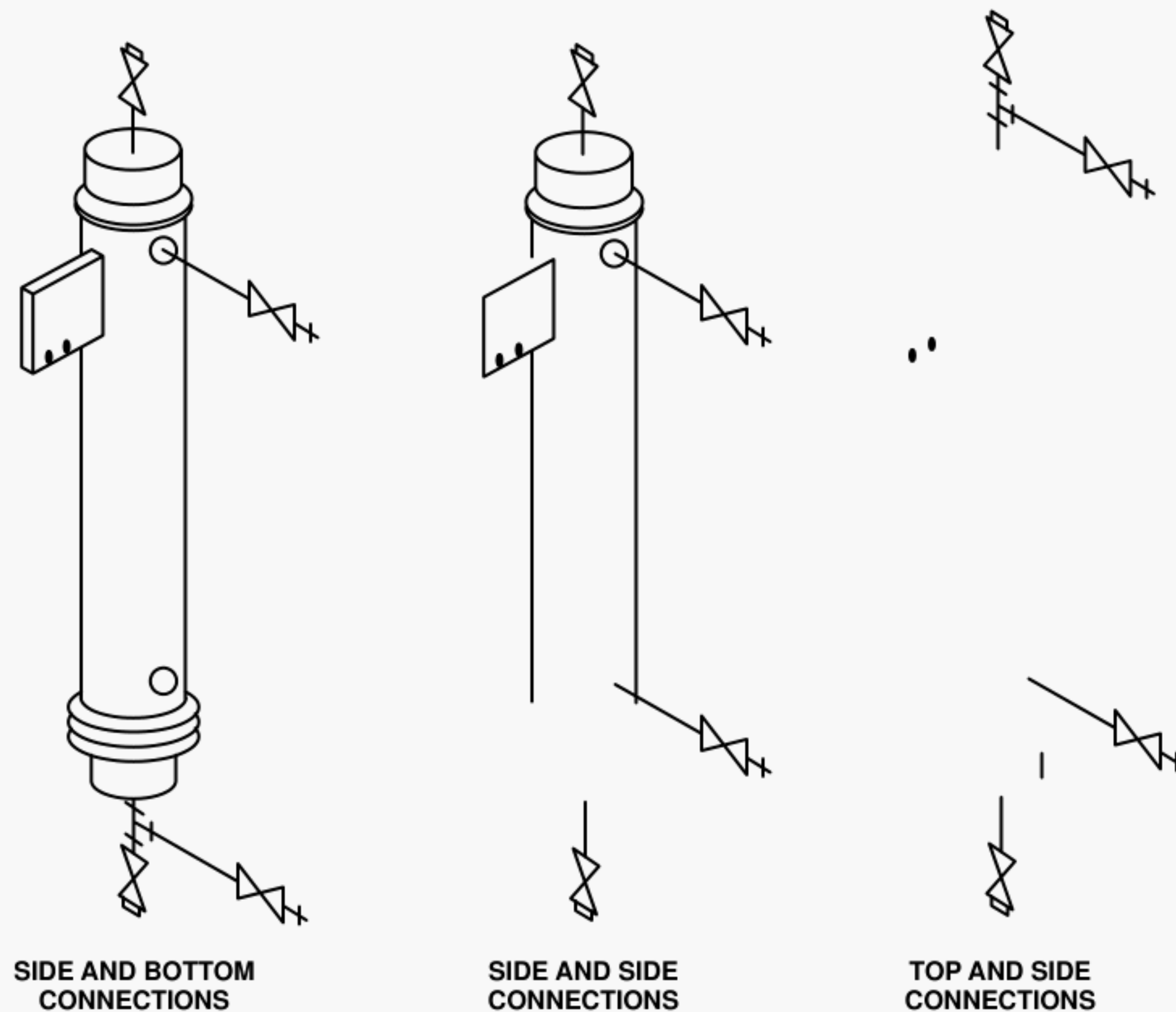


Figure 10—External-Cage Displacement Instrument

The arrangement shown in Figure 12 permits direct calibration of a transmitter or controller with the vessel either in or out of service. This can be done by manipulating the block, drain, and vent valves so that the level of the fluid is run up and down in the gauge glass and transmitter in parallel.

Nozzle spacing on the vessel is critical on close-coupled installations, especially where side connections are used, because of differential expansion of the vessel and the controller. In cases where levels of considerable range are to be transmitted, it may be preferable to use other types of transmitters.

3.4.2.6 Internal Displacers

Occasionally, the displacer may be mounted inside the vessel rather than in an outside cage. For example, when it is desirable to avoid steam tracing, the vessel nozzle and the head casting of the instrument must be provided with mating flanges of the type and specification required by the service. Where possible, it is generally preferable to use steam-traced external displacers. Internal displacers should be avoided, particularly on vessels that cannot be isolated without part of the plant being shut down.

Ample clearance must be provided for removal of the displacer and rod. When a side mounting is required, provision

should be made for access to the displacer, for example, a manhole.

Guides are required in many internal displacer installations. For side-mounted displacers, a stilling well (see Figure 13) is usually provided for this purpose, although rod or ring guides are sometimes used. Ring guides are particularly suitable for emulsion service.

3.4.3 DIFFERENTIAL-PRESSURE TRANSMITTERS

3.4.3.1 General

Differential-pressure transmitters respond more quickly than do external-cage displacement transmitters and require less range for stable control.

3.4.3.2 Low-Displacement Transmitters

Applications of low-displacement transmitters include remote control and remote indicating or recording of liquid level. This type of transmitter (usually the blind type) generally has an adjustable range and can have a high span-elevation/suppression capability. A receiver-type indicator may be provided on the transmitter's output for local indication.

Connections to the vessel can be made by means of pipe fittings of the material and rating recommended for the ser-

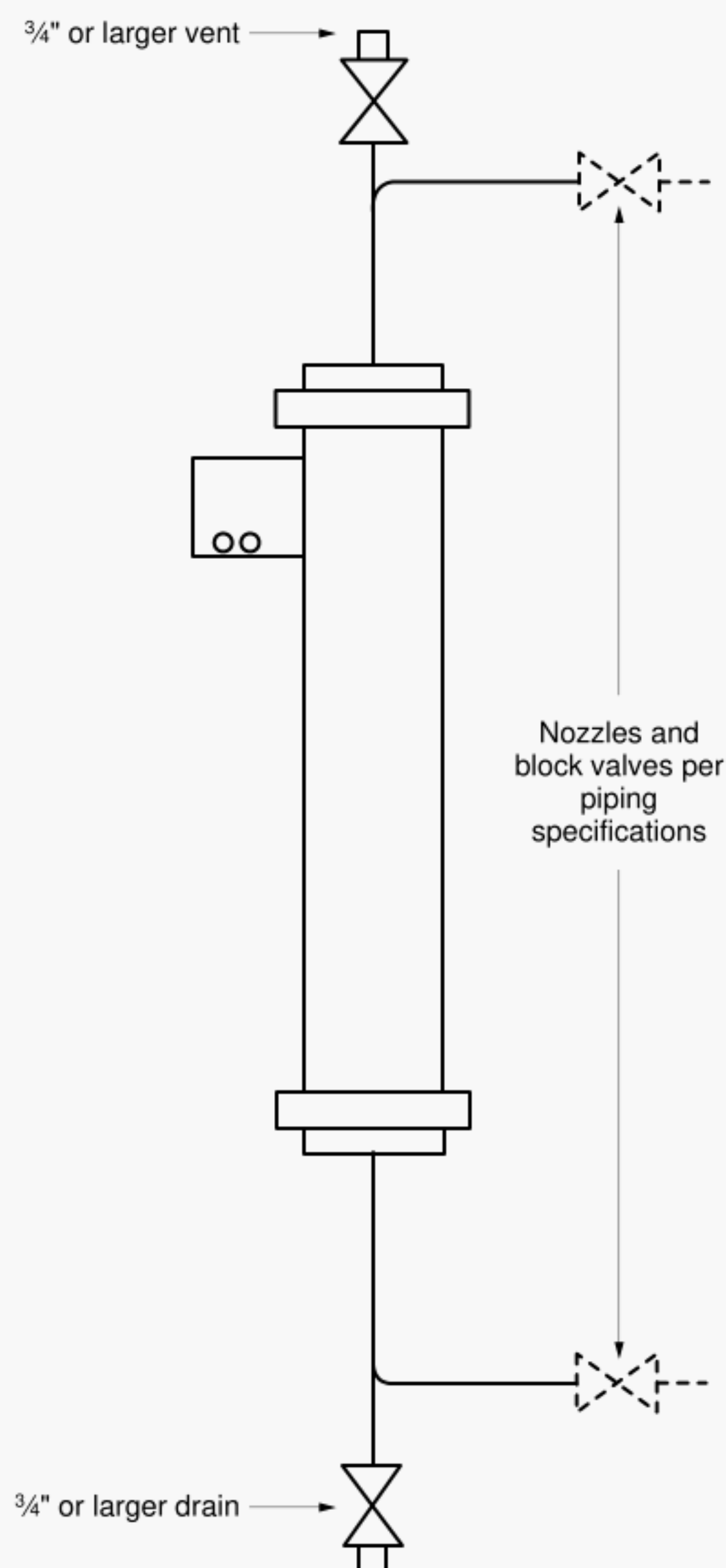


Figure 11—External-Cage Displacement Controller With Standpipe

vice or by means of $\frac{1}{2}$ - or $\frac{3}{4}$ -inch tubing and tubing fittings. The vessel connections should be at least $\frac{3}{4}$ inch in size (see 3.2.6.2).

The transmitter should not depend on its own piping for support but should be yoke or bracket mounted. Typical installations are shown in Figure 14.

Constant head can be maintained on the external or reference leg of the transmitter, as shown in Panel A of Figure 14. Because displacement of the measuring element with measurement changes is minimal, even with condensables, no seal pot is required.

Figure 15 shows a flange-connected transmitter mounted directly on the tank. This type of transmitter is used advantageously to measure slurries or viscous fluids. If required,

the sensing diaphragm can be mounted flush with the inside of the vessel. Various diaphragm materials are available for corrosive services. Figure 15 shows a typical installation.

Where hydraulic resonance may occur or where boiling liquid may cause violent agitation of the liquid surface, a differential-pressure instrument can be used to advantage, since (a) its output can be damped and (b) a seal liquid can be used to avoid boiling in the external legs.

For vacuum service or service with volatile liquids, a suitable seal liquid or purge should be used in both legs. When external seals are used, this type of transmitter requires the use of seal pots to maintain a constant external head and ensure accuracy (see Section 6).

3.4.4 HYDROSTATIC-HEAD TRANSMITTERS

3.4.4.1 Installation

Hydrostatic head may be transmitted either by means of a bubbler tube and pressure transmitter or by means of a diaphragm- or bellows-actuated transmitter mounted directly on the vessel. The latter type of transmitter should be mounted on a flanged nozzle at a point where it will not be subject to blocking by sediment.

3.4.4.2 Precautions

Bubbler tubes must be sized to prevent pressure-drop errors that result from purge gas flow. They must be installed so that sediment cannot block the open ends, and they should be supported, if necessary, so that turbulence or mechanical strains cannot bend or break them. For greatest accuracy, the connecting leads must be leakproof. Bubbler-type transmitters are not normally used in closed or pressurized systems.

3.4.5 NUCLEAR LEVEL TRANSMITTERS

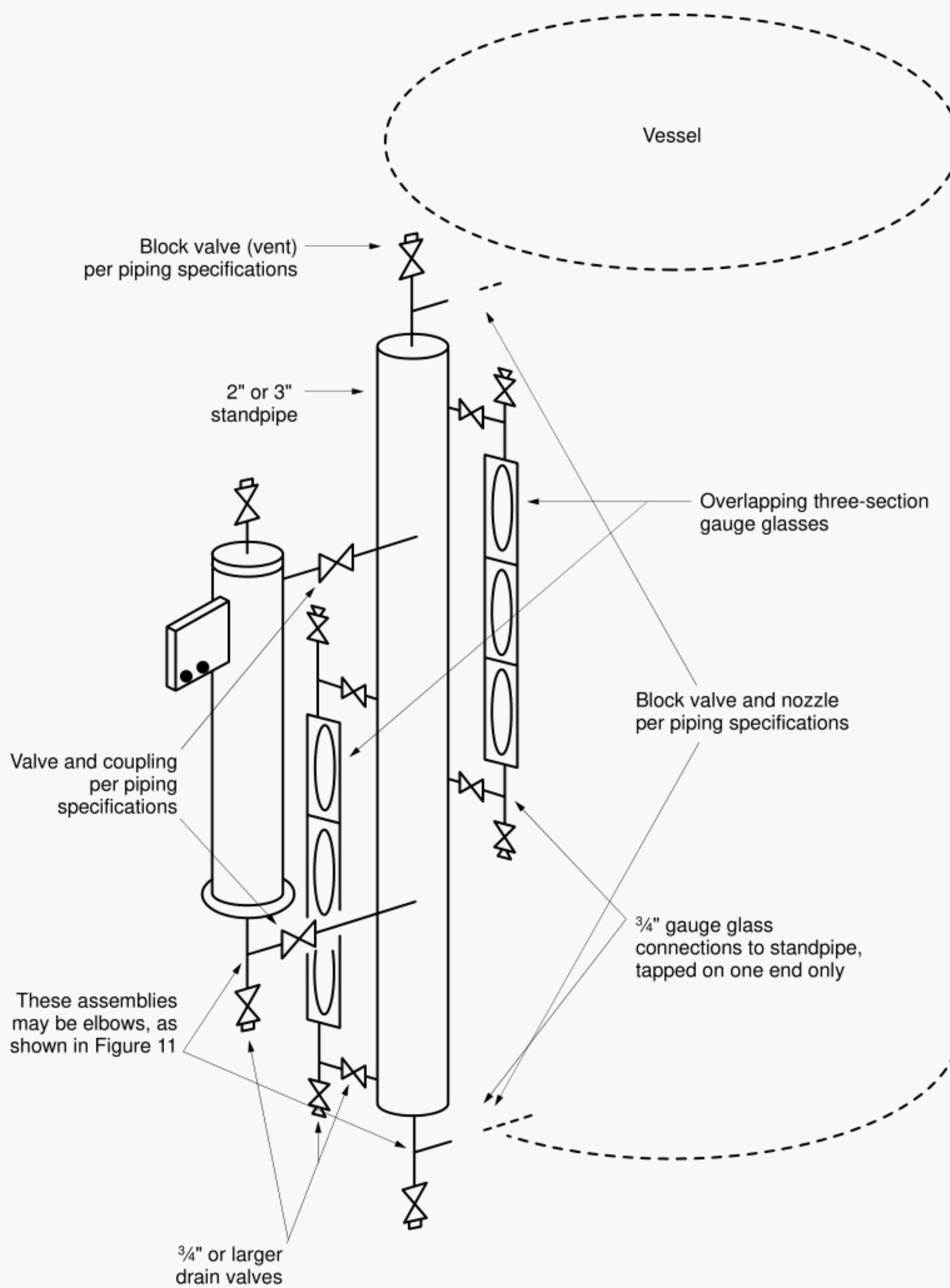
3.4.5.1 General

Nuclear level instruments are used where other types of internal or external instruments cannot be used, such as in coking or vacuum towers.

3.4.5.2 Operation

Nuclear level instruments measure by means of beta or gamma rays that are sensed by radiation detectors. A radioactive source is placed so that the vessel contents are between the source and the detector. When the vessel is empty the count rate is high, and as the level rises the count rate decreases.

The strength of the radiation sensed by the detector depends on the density and thickness of the material in the vessel, the distance between the source and the detector, and the thickness of the vessel wall and insulation. The range is limited by the size of the source (factory selected for the application). Multiple sources are sometimes used to measure wide ranges (see Figure 16).



Note: The instrument may be piped with side and bottom or side and side connections, as shown in Figure 10.

Figure 12—Standpipe With External-Cage Displacement Instrument and Multiple Sight Gauges

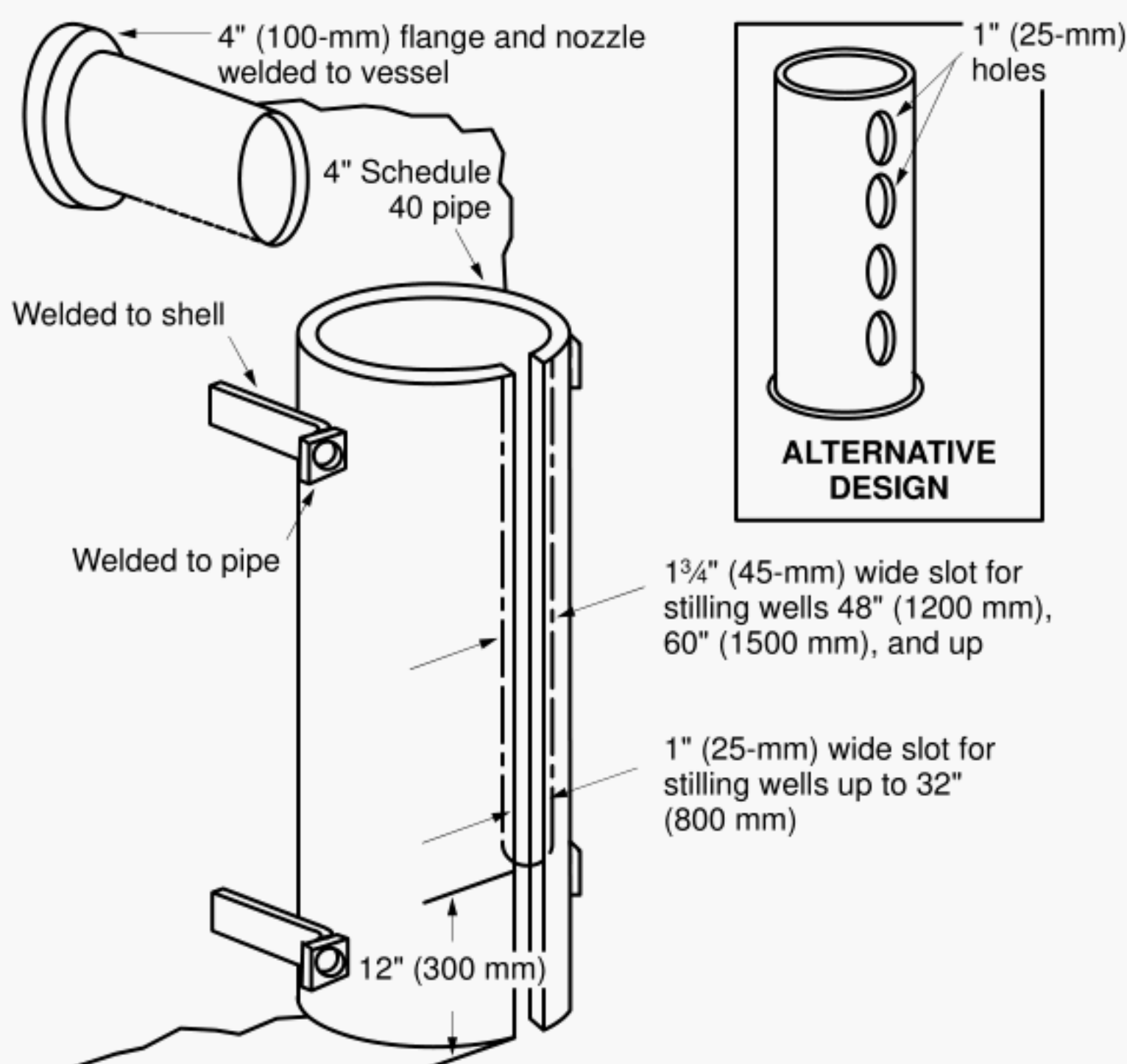


Figure 13—Typical Stilling Well

3.4.5.3 Precautions

The design of the source container, the size and location of the source, and the source's handling must comply with all local, state, and federal requirements. Plants are required to have licensed safety personnel who are familiar with the requirements and safety procedures.

The user should review the design of the source container to ensure that it meets fire safety requirements, as well as current state and federal regulations limiting the use of nuclear devices.

3.4.5.4 Installation

Because of regulatory requirements, nuclear level instruments must be installed in compliance with manufacturers' instructions and nuclear codes.

3.4.6 ULTRASONIC LEVEL TRANSMITTERS

3.4.6.1 Operation

Ultrasonic transmitters measure the time required for sound waves to travel through space. A sound transmitter (transducer) converts an electrical pulse to sound waves that reflect off the level surface being measured. The reflected signal is detected by either the same or another transducer.

Since the speed of sound through the medium above the level surface can be determined, the measured time from signal transmission to reception is proportional to the level.

The speed of sound varies with the temperature, composition, and elevation of the vapor space.

3.4.6.2 Installation

Ultrasonic units should not be installed in areas with strong electrical fields (motors, relays, electric generators, and so forth).

3.4.6.3 Precautions

Application parameters must be reviewed carefully to ensure the correct use of ultrasonic devices. Factors such as variations in process pressure and temperature, relative humidity, and concentrations of gases and vapors will affect sound velocity. Compensation for these variables is available.

3.4.7 CAPACITANCE/RADIO-FREQUENCY LEVEL TRANSMITTERS

3.4.7.1 Operation

A capacitor consists of two conductive plates separated by an insulator. Its capacitance is a function of the area of the

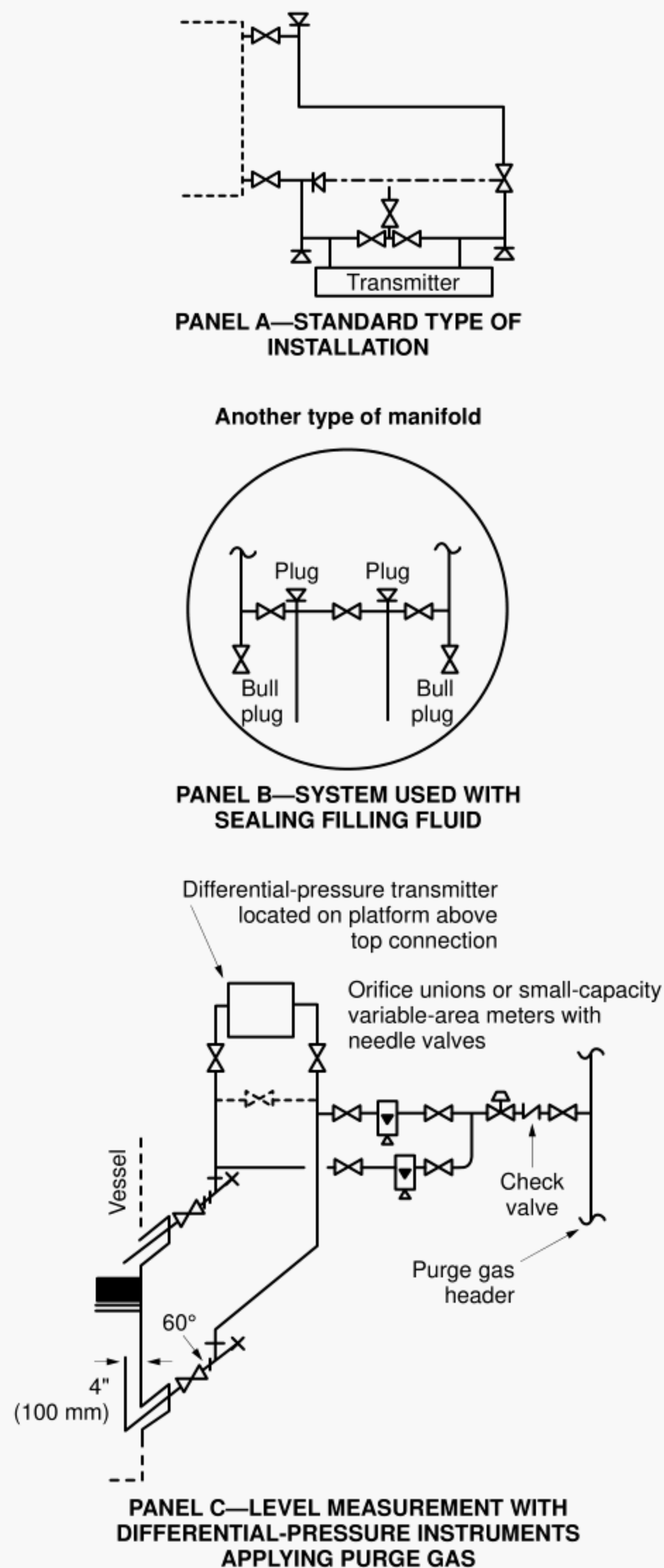


Figure 14—Typical Installations of Differential-Pressure-Level Instruments

plates, the spacing between them, and the dielectric constant of the insulator.

A capacitance level transmitter consists of a vertical sensing element that is inserted into the vessel in which the level

is to be measured. The sensing element may be either plain (bare metal) or sheathed with an insulating material and serves as one of the plates of the capacitor.

If the vessel is an electrical conductor and the material (liquid or granular) being measured is an insulator, a plain sensing element is normally used. In this case, the vessel serves as the other plate. Since the dielectric constant of the material being measured is different from that of the air, vapor, or gas being displaced, the electrical capacitance between the sensing element and tank varies with level.

If the material being measured is an electrical conductor, an insulated sensing element is used. In this case, the element serves as one plate, the sheath serves as the insulator, and the material being measured replaces the tank as the other plate. The size of the capacitor plate, and therefore its capacity, varies with level.

More sophisticated circuits, which measure both capacitance and resistance current, can correct for sensor buildup and composition changes.

When a liquid-liquid interface is measured and one phase is aqueous, the water phase is measured, since the change in capacitance of the insulating phase is relatively insignificant.

Circuitry varies widely from manufacturer to manufacturer, so selection should be carefully reviewed with the manufacturer.

3.4.7.2 Installation

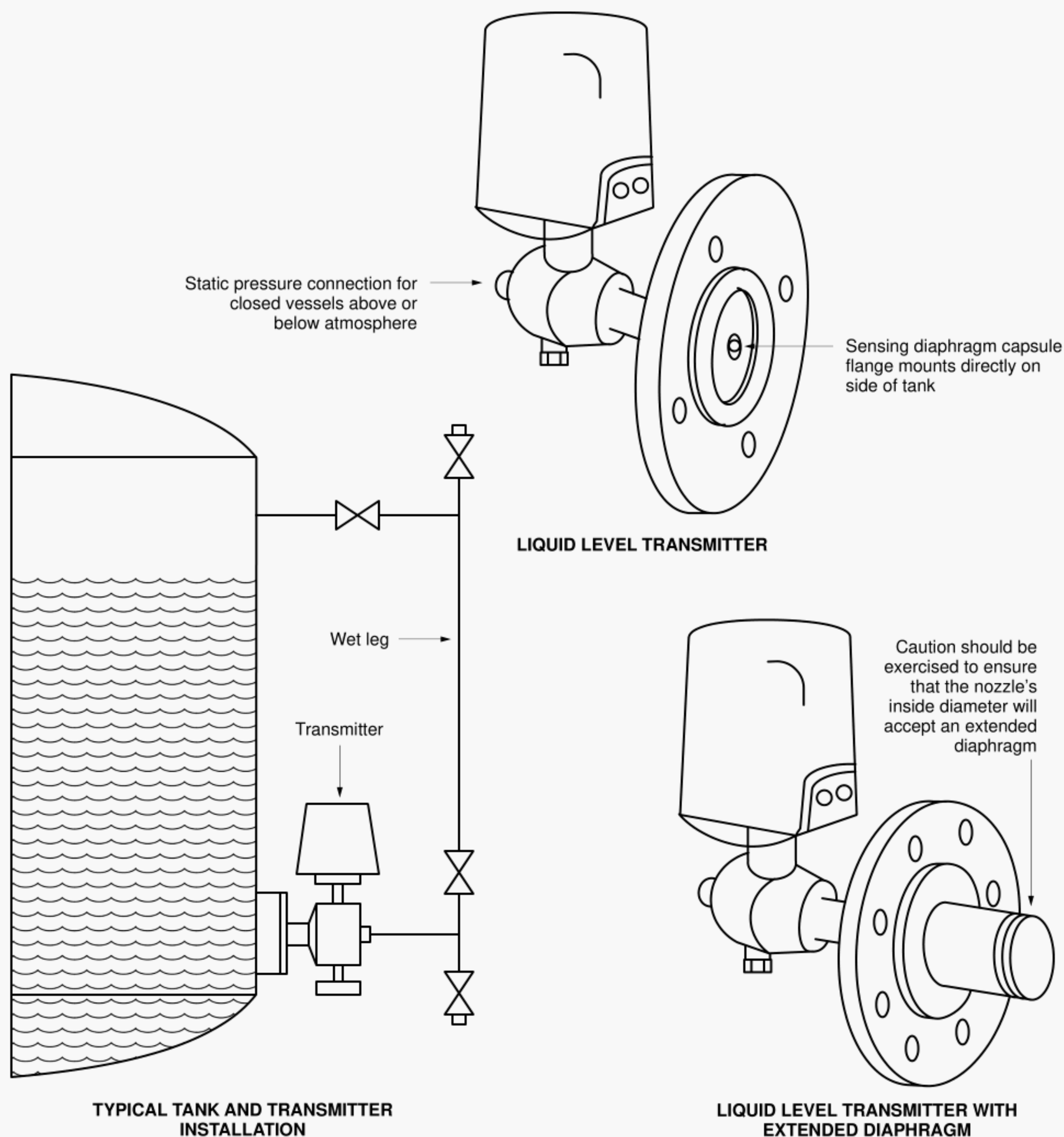
The sensing element must be vertical and must not be in contact with the vessel wall or internals. Applications in which both the container walls and the medium are nonconductive may require a counterelectrode (ground reference) made from a conductive material. The need for and type of ground reference should be reviewed with the manufacturer.

The user should review the design of the sensing element's seal for fire safety and should review the design of electrical and electronic circuitry to ensure that it meets explosionproof or intrinsic safety requirements or both.

The following are available for internally mounted sensing elements:

- Precalibration capability if a concentric shroud is supplied.
- Sensing elements that can be installed or retracted under operating conditions with the plant running.
- Sensing elements that cover the temperature range from liquid gases to hot catalyst pellets.

With a capacitance/radio-frequency sensing element in an external cage, the difference in density due to temperature that results in a lower liquid level in the chamber is, to a large degree, offset by the higher dielectric constant of the denser liquid; hence, the indicated level will be close to the vessel's liquid level (see Figure 17).



Note: Compensation is available to balance out the initial hydrostatic head in the wet leg.

Figure 15—Flange-Type Differential-Pressure-Level Transmitter

3.5 Locally Mounted Controllers

3.5.1 GENERAL

Locally mounted controllers used on all pressure vessels include the displacement, caged ball-float, internal ball-float, and differential-pressure types.

3.5.2 DISPLACEMENT CONTROLLERS

Recommended practices for the installation of displacement controllers are the same as those for equivalent types of transmitters and are outlined in 3.4.2. “Dual-pilot” displacement instruments provide both local control and transmission from a single displacer.

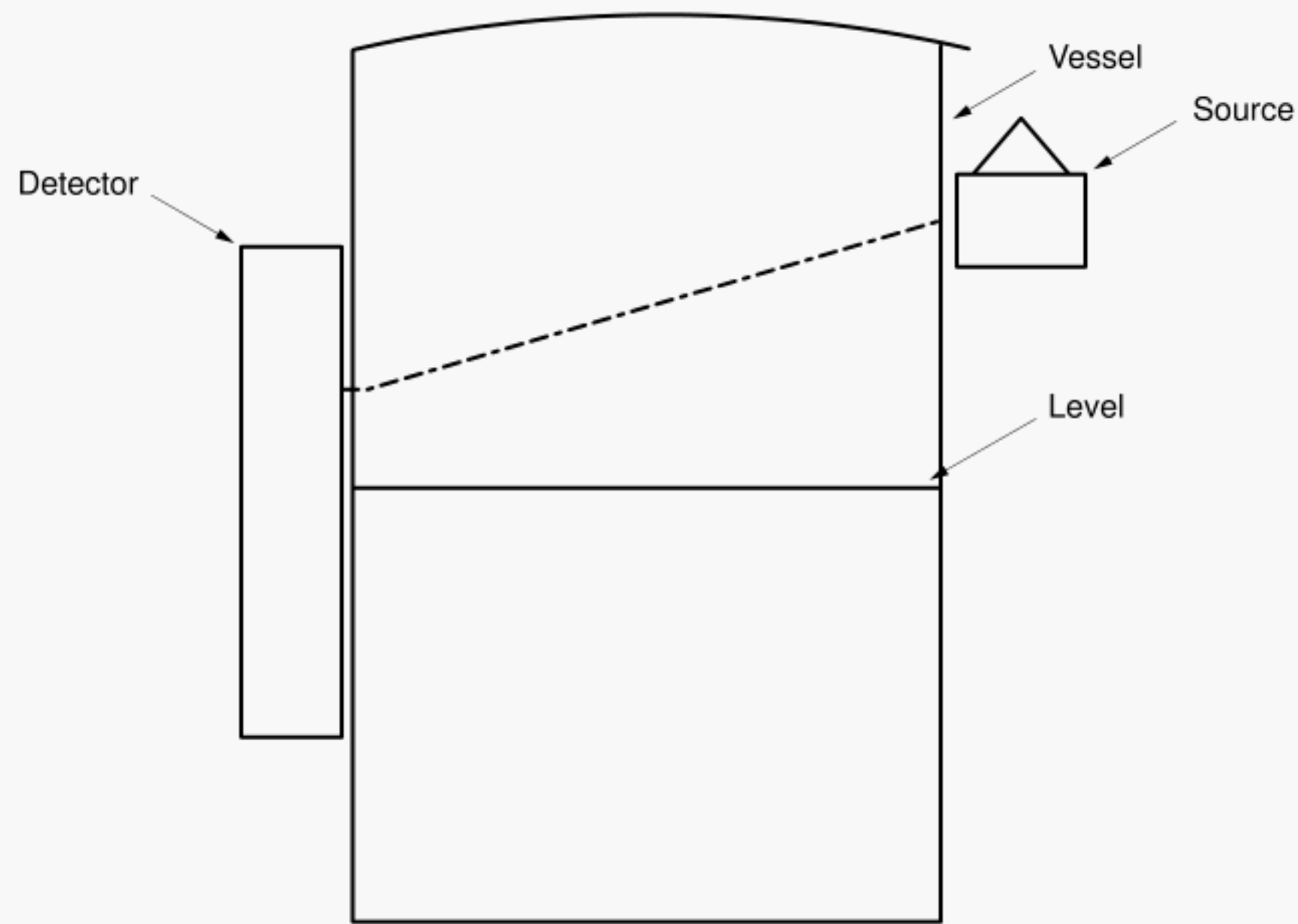


Figure 16—Typical Arrangement for Nuclear Level Transmitter

3.5.3 INTERNAL BALL-FLOAT CONTROLLERS

3.5.3.1 Application

An internal ball-float controller is sometimes used for asphaltic or waxy fluids, for coking service, or for liquids that

contain particles or materials that tend to settle out and would eventually block the float action in an external-cage type of instrument. In severe coking applications, it may be desirable to use a steam or flushing-oil purge to keep the float clean, the shaft free, and the packing in suitable condi-

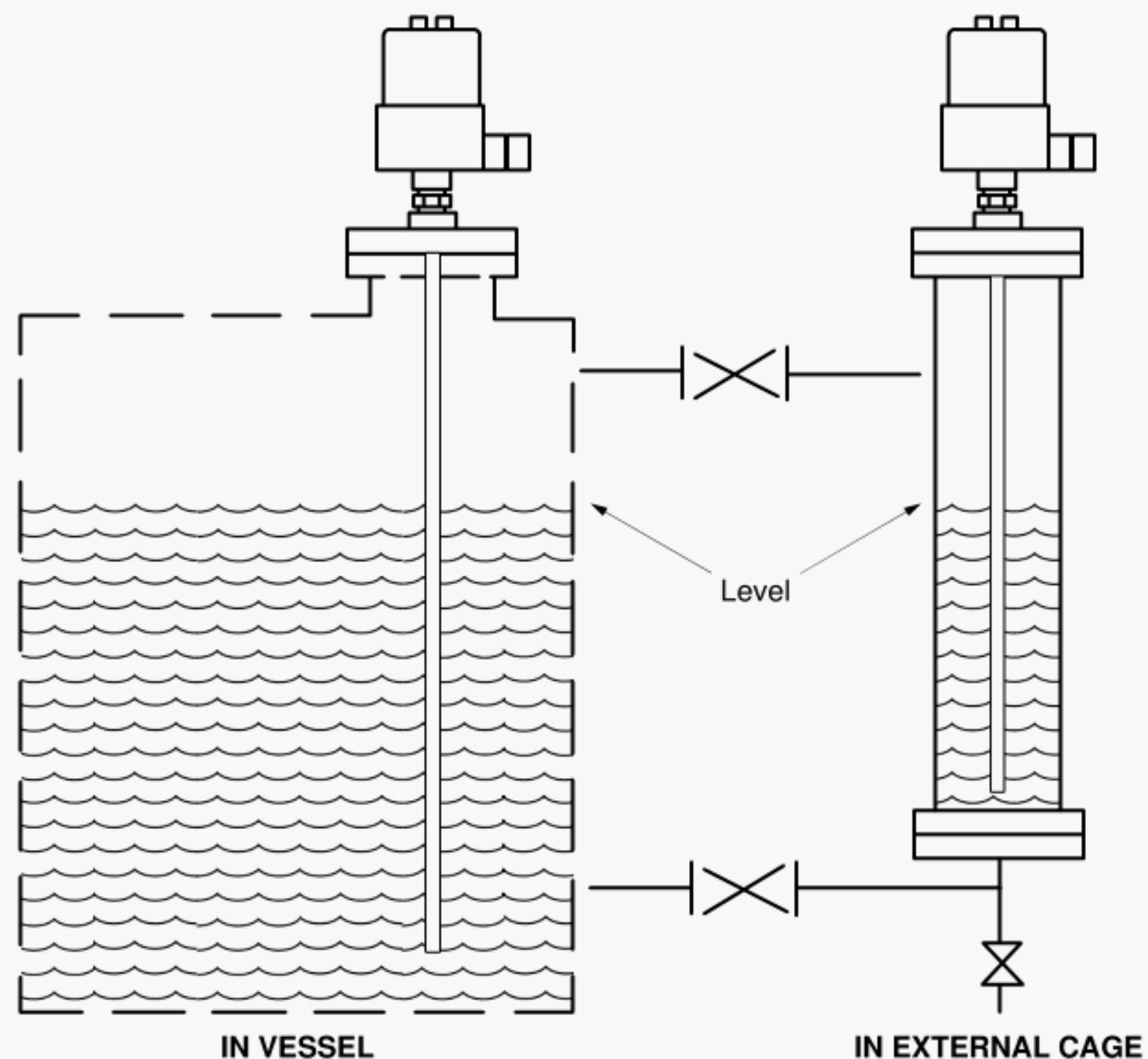


Figure 17—Capacitance/Radio-Frequency-Type Level Transmitter

tion. In such applications, it is preferable to use other types of level devices.

3.5.3.2 Installation

Where the float will be subjected to turbulence within the vessel, shields, guides, or other provisions should be made to eliminate the effects of turbulence on the float. Pneumatic piping or electrical wiring to such instruments should be in accordance with the practices for transmission outlined in API Recommended Practice 552.

3.5.3.3 Supplemental Indicator

In severe services, as noted in 3.5.3.1 and 3.5.3.2, the controller should be supplemented by another type of instrument (for example, differential pressure, capacitance/radio frequency, or another special type).

3.5.4 DIFFERENTIAL-PRESSURE CONTROLLERS

The most common use of differential-pressure level transmitters is with a separately mounted receiver-controller. The

installation of differential-pressure controllers is basically the same as that for differential-pressure transmitters (see 3.4.3.1 and 3.4.3.2).

3.6 Level Switches

3.6.1 GENERAL

The basic considerations for instruments used to initiate high- or low-level alarm signals are, with the possible exception of float size, the same as those discussed in 3.4 and 3.5. Other types of switches (for example, pressure switches at the receiver in pneumatic transmission systems, hydrostatic-head pressure-actuated switches on nonpressurized tanks, and capacitance/radio-frequency- and differential-pressure-actuated switches on pressurized or nonpressurized vessels) are sometimes used. For a detailed discussion of alarms and protective devices, refer to API Recommended Practice 554.

3.6.2 INSTALLATION OF FLOAT SWITCHES

The installation of float switches is the same as that of the displacement transmitters covered in 3.4.2. A typical installation of high- and low-level alarm switches with a parallel

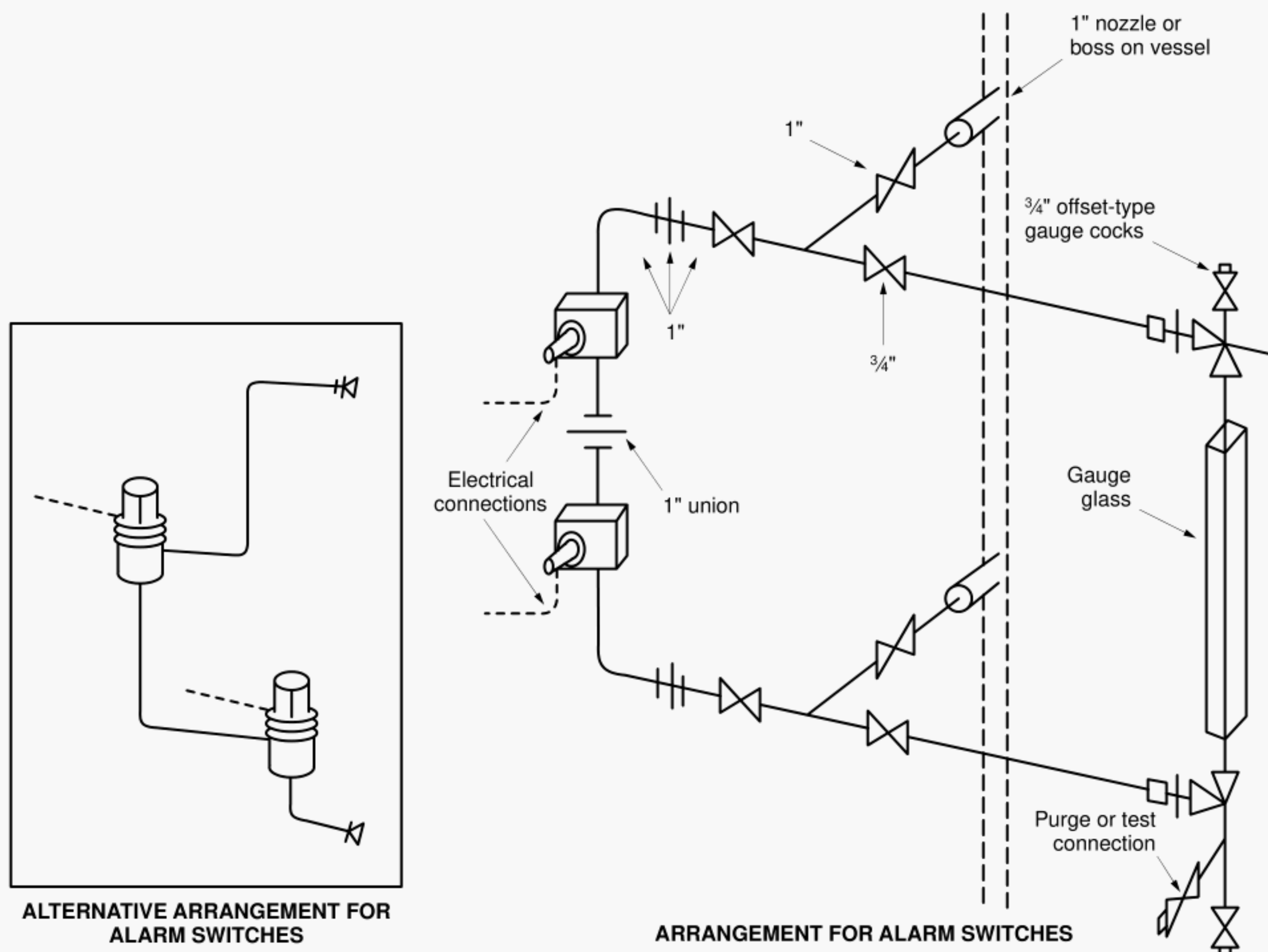


Figure 18—Arrangement of High- and Low-Level Alarm Switches With Parallel Gauge Glass

gauge glass is shown in Figure 18. Level switches used as protective devices should have separate connections to the vessel, independent of other instruments.

3.6.3 INSTALLATION OF OTHER SWITCHES

Electronic switches, such as capacitance/radio-frequency and sonic switches, can be installed in vessels or external cages in an arrangement similar to that shown in Figure 18.

Pressure switches in pneumatic transmission circuits are normally installed with block valves and often with a plugged test tee. A sensitive pressure-actuated switch or a differential-pressure-actuated switch mounted directly on a tank or vessel to signal high or low hydrostatic head should be located at a point that is not subject to blocking by sediment.

3.6.4 TESTING

When switch action is critical or when plant standards or regulations (for example, Occupational Safety and Health Administration) require periodic switch testing, this can be done by installing a hydraulic connection at the alarm point on the tank and piping the connection to a chamber near ground level in which the sensor is installed. When the alarm level is reached, fluid flows through the pipe and fills the chamber, activating the alarm. For testing, some of the actual fluid is poured into the chamber to fill it. This arrangement provides a total dynamic test and permits servicing without requiring personnel to climb the tank.

In some cases, electronic switches can be provided with special testing circuits that are actuated by push buttons or a specifically programmed microprocessor.

Float or displacement level instruments may have a lever or pull that permits checking of the field unit by pushing up the float or displacer. For this test to be valid, some means of limiting the force applied during checking is required. If the float or displacer is stuck, the lever could free it without the technician being aware of doing so.

3.6.5 OVERFILL PROTECTION

API Recommended Practice 2350 provides information on overfill protection.

3.7 Tank Gauging

The level transmitters discussed in this section can be used for in-plant noninventory storage tanks. For inventory or other high-accuracy gauging, refer to API Standard 2545.

3.8 Accessories

3.8.1 SEALS AND PURGES

It is occasionally necessary to use seal pots or purges in connection with liquid level instruments (see Section 6).

3.8.2 WEATHER PROTECTION

Section 6 covers weather protection.

SECTION 4—PRESSURE

4.1 Scope

This section discusses recommended practices for the installation of the instruments and devices commonly used to indicate, record, and control the pressures and differential pressures normally encountered in petroleum refinery processes. The instruments covered are pressure gauges and switches, pressure transmitters, and locally mounted controllers and recorders.

4.2 General

4.2.1 INTRODUCTION

Certain general procedures, practices, and precautions apply to all of the instruments discussed in this section. Where applicable, the material discussed in 4.2.2 through 4.2.10 should be considered a part of each of the subsequent discussions.

4.2.2 APPLICATION PRACTICE

Hydrocarbons or other process fluids that may be hazardous or otherwise undesirable in the control room in the event of leakage should not be piped to any instruments located in a central control room. It is industry practice to transmit the pressure of such fluids either electrically or pneumatically to receiving instruments. It is also the practice to transmit the pressure of fluids to local installations where long piping or capillary systems would otherwise be required. Examples include instances in which solids present in the process fluid could cause plugging or in which differences in elevation could result in liquid head problems. Insulation and heating of long leads to prevent freezing can also be eliminated by the use of transmission systems.

4.2.3 ACCESSIBILITY

All locally mounted pressure instruments should be readily accessible from grade, platforms, fixed walkways, or

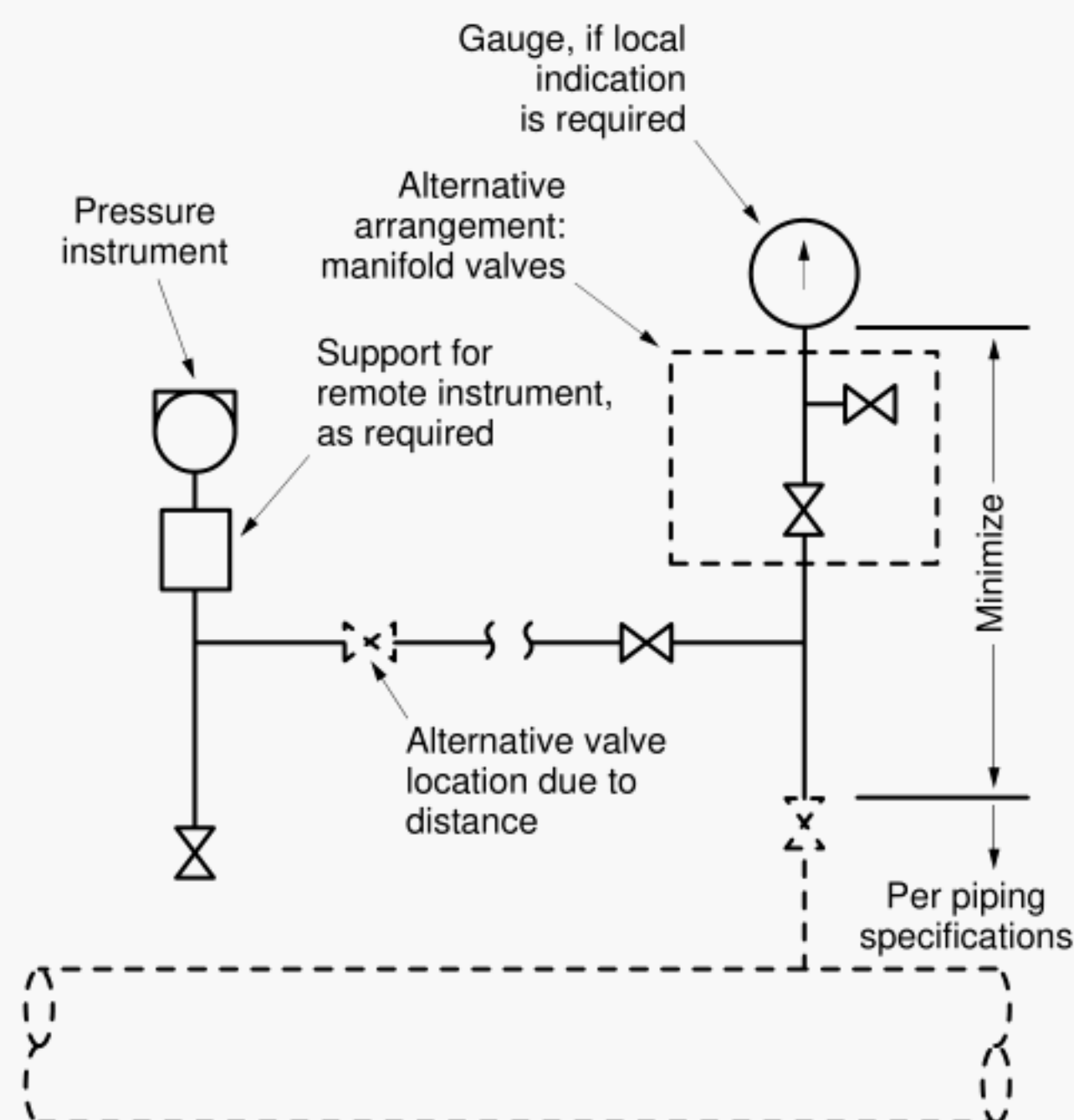


Figure 19—Piping for Pressure Instruments That Share a Common Process Connection

fixed ladders. A rolling platform is sometimes used where free access is available to the space below the instruments.

4.2.4 LOCAL INDICATION

Where local indication is desired and nonindicating (electronic and pneumatic) transmitters, switches, and locally mounted pressure controls are used, these instruments should be supplemented with directly connected process pressure gauges (see Figure 19), output indicators, or both. A sup-

pressed-zero pressure transmitter should be supplemented with a full-range process pressure gauge, even if the transmitter is equipped with an output indicator.

In applications where pressure can be manually controlled at a control valve station, some indication of pressure should be clearly visible and readable from the valve location to permit manual control when necessary. Such indication is not necessary if the control system cannot be manually operated from the control valve station.

4.2.5 VIBRATION

Most pressure instruments are susceptible to damage, abnormal wear, or malfunction if they are mounted in locations where they are subject to vibration. If any part of the pressure system or equipment is subject to vibration, the instrument should be mounted on a vibration-free remote support. Coiled tubing, armored hose, or a capillary system should be provided between the pressure source and the instrument.

4.2.6 PULSATION

Instruments that measure the pulsating pressures of reciprocating pumps and compressors should be equipped with pulsation dampeners to prevent premature failure of the movements or the pressure elements. Needle valves, floating pins, or porous metal devices are often used for this purpose (see Figure 20). Indicating pressure gauges with liquid-filled cases should also be considered for pulsating-service applications.

4.2.7 PURGING AND SEALING

When viscous liquids or pressures of corrosive process fluids are measured or when plugging is possible where solids exist, an instrument may be sealed, purged, or protected by a diaphragm seal or protector (see Figure 20).

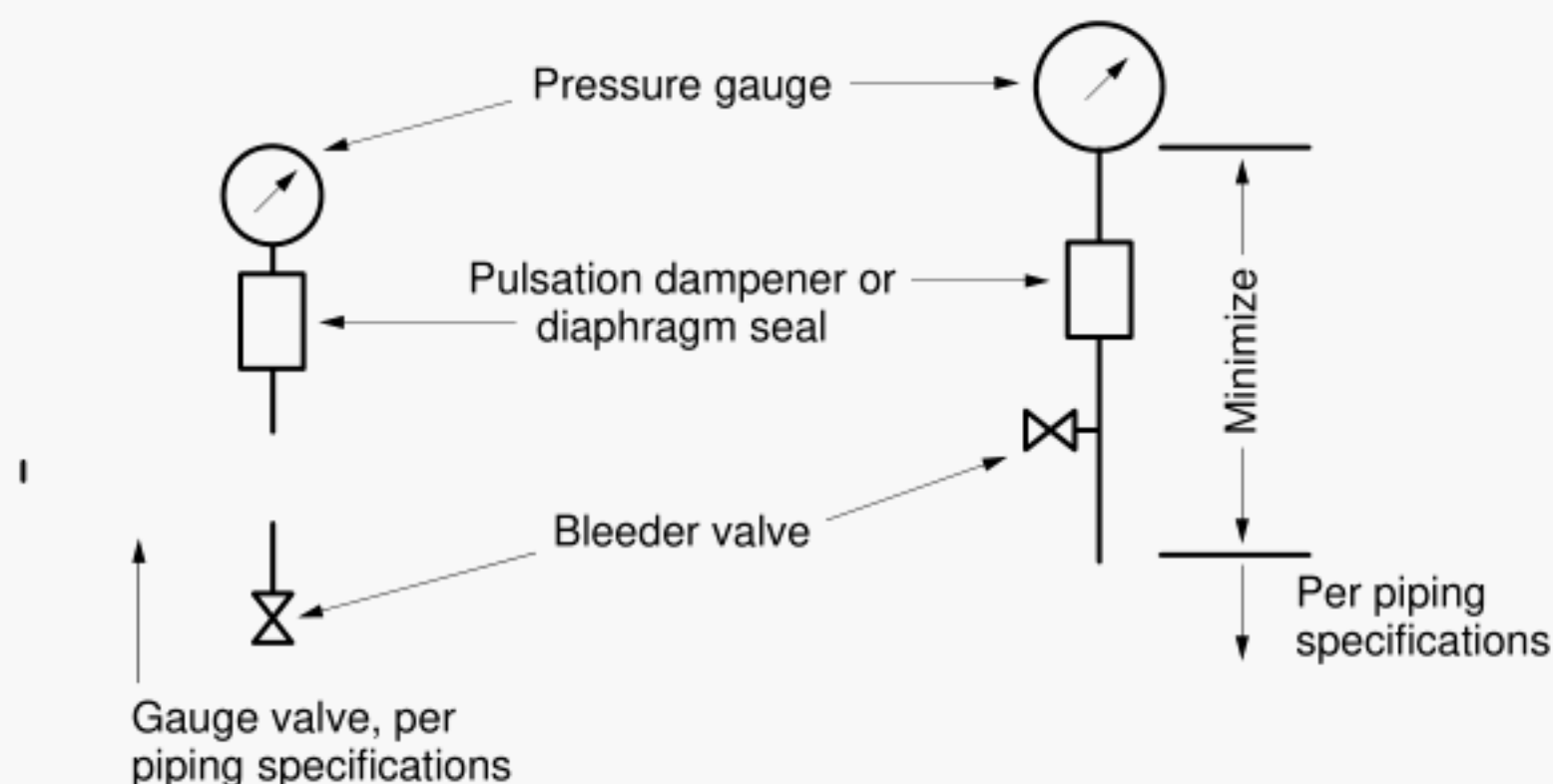


Figure 20—Piping for Pressure Gauges in Pulsating, Corrosive, Slurry, or Freezing Fluid Service

The diaphragm seal unit should have a flushing connection and wetted parts of a suitable material to resist corrosion.

Diaphragm seals with or without capillary leads are becoming more widely accepted because of the availability of suitable filling fluids. Nonflammability, low vapor pressure, and low coefficient of expansion are characteristics of the fluids used. To minimize heat tracing, some prefer diaphragm-sealed pressure gauges on all fluids that freeze at ambient temperatures. Manufacturers can supply instruments complete with the seal and capillary assembled.

The required accuracy should be investigated for filled-system units. Errors increase as the range decreases. Care should be taken to isolate the capillary from any variable heat source such as heat tracing or process piping. Pressure-differential-sensing instruments should use a pair of capillary leads that are of equal length and follow the same path to minimize error due to thermal expansion. Capillary leads should be kept as short as possible, since response time increases with length. Response time is also influenced by temperature and the type of filling fluid.

A purge is commonly used for pressure instruments in fluidized-solid service. Refer to Section 6 for additional information on seals, purge quantities and methods, and location of purge points.

4.2.8 PIPING

4.2.8.1 Size and Design

Process connections to instruments should be furnished and installed in accordance with applicable piping and material specifications. When pipe is selected, ½-inch Schedule 80 pipe and fittings should be used. When tubing is selected, tubing with an outside diameter of ½ or ¾ inch and a minimum wall thickness of 0.035 inch is generally acceptable. To reduce or eliminate corrosion and to eliminate the expense of cleaning and painting, stainless steel or alloy tubing is some-

times used where carbon steel would otherwise be acceptable.

For instruments that have connections smaller than ½ inch nominal pipe size, the line size should be reduced at the instrument. The first block valve at the process connection should conform to process piping specifications and should normally be ¾ inch in size (a minimum of ½ inch in size; see Figure 19). Some companies prefer to use extended-body gate valves for small piping in accordance with API Standard 606. Some users permit valves of the same rating but less rigid specifications for secondary valving in the manifold. To avoid damage to the connected instrument, the instrument should be disconnected during hydrostatic testing.

4.2.8.2 Cleaning

All pipe should be deburred after cutting and blown clean of cuttings and other foreign material. This subject is usually covered by the applicable process piping specification.

4.2.8.3 Short Connections

The most satisfactory and economical installation of a pressure device is usually achieved by coupling the device as close to the process connection as is practicable, consistent with accessibility and visibility requirements (see Figure 21). This practice requires less material and heat tracing, eliminates vapor traps and liquid head problems, and reduces the possibility of leaks and plugging.

4.2.8.4 Long Connections

Where the process block valve is not readily accessible from the instrument location, an additional block valve and a bleed valve should be installed at the instrument.

When several pressure-measuring devices are manifolded from one process pressure tap, good practice requires separate block and bleed valves for each pressure instrument (see Figure 19).

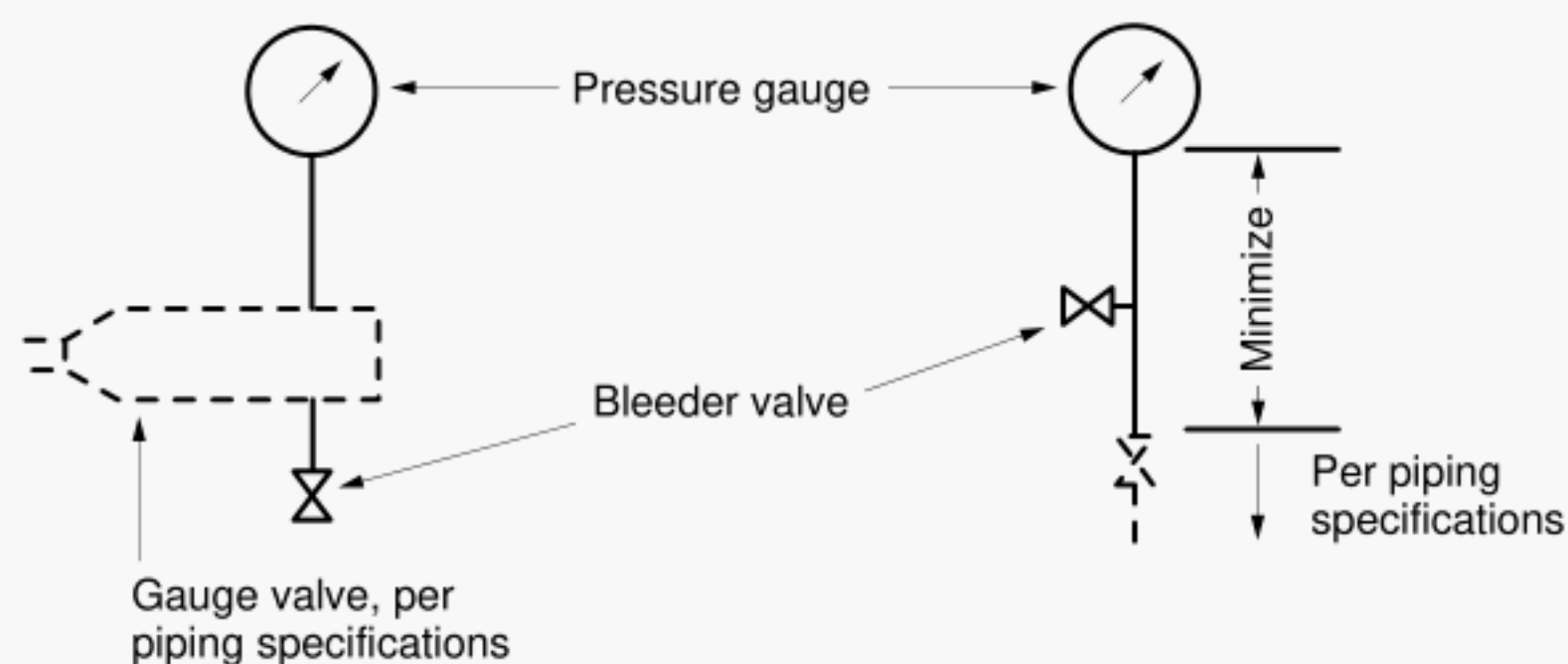


Figure 21—Pressure Gauges Supported by Piping

4.2.8.5 Piping Flexibility

Instrument pressure piping should be installed and supported so that the forces developed from the expansion of hot piping or vessels cannot result in piping failure or strain on the instrument. High-pressure armored hose or coiled tubing can be used where a high degree of piping flexibility is required.

4.2.9 ENCLOSURES

If the manufacturer's standard case is not adequate, enclosures should be provided to protect locally mounted instruments from ambient conditions. The enclosures must not restrict bleed air from pneumatic instruments nor heat dissipation from electronic devices. The area classification may require special enclosures to meet the requirements of NFPA 70 and other national or local codes.

4.2.10 ELEMENT AND SOCKET (WETTED) MATERIALS

Materials should be selected to withstand corrosion from the process fluid and environmental conditions. Direct pressure elements, such as bourdon tubes and bellows, are thin and afford minimum corrosion allowance. Type 316 stainless steel is the most commonly used material in corrosive service for elements, sockets, and other wetted parts. Bronze is commonly used for air, sweet water, and inert gases. Monel is a superior material for caustic and salt solutions where chloride stress corrosion might adversely affect stainless steel. Other materials are available for special situations, but in severely corrosive conditions, the use of a diaphragm seal of suitable material is a more common choice (see 4.2.7).

4.3 Pressure Gauges and Switches

4.3.1 CONNECTIONS

Indicating Bourdon-tube pressure gauges and switches for flush mounting on local field-instrument panels should be back connected. Surface- and field-mounted gauges and switches should be bottom connected. For mechanical strength, the recommended connection size is $\frac{1}{2}$ inch.

4.3.2 SUPPORTS

A gauge or switch may be supported by its piping if it is close coupled to the process connection (see Figure 21). Where vibration is anticipated, good practice requires independent support (see 4.2.5, 4.2.8.5, and Figure 22).

4.3.3 SAFETY DEVICES

Every process pressure gauge should be provided with a device, such as a disk insert or blowout back, designed to relieve excess case pressure. Such a device can prevent bursting of the glass or the case in the event the pressure element fails. Some users also require a solid-front gauge design for gauges in high-pressure service. Gauges are available with safety glass or plastic windows as an additional safeguard. Gauge supports should be designed so that the blowout disk is not covered. Field gauges should not be painted, and insulation over heat tracing should not cover or restrict the disk or blowout back. Excess-pressure cutouts, with or without velocity checks, are available for limiting overrange.

4.3.4 SIPHONS

Siphons or "pigtail" condensate seals should be provided for steam or other hot condensable vapors when the gauge is

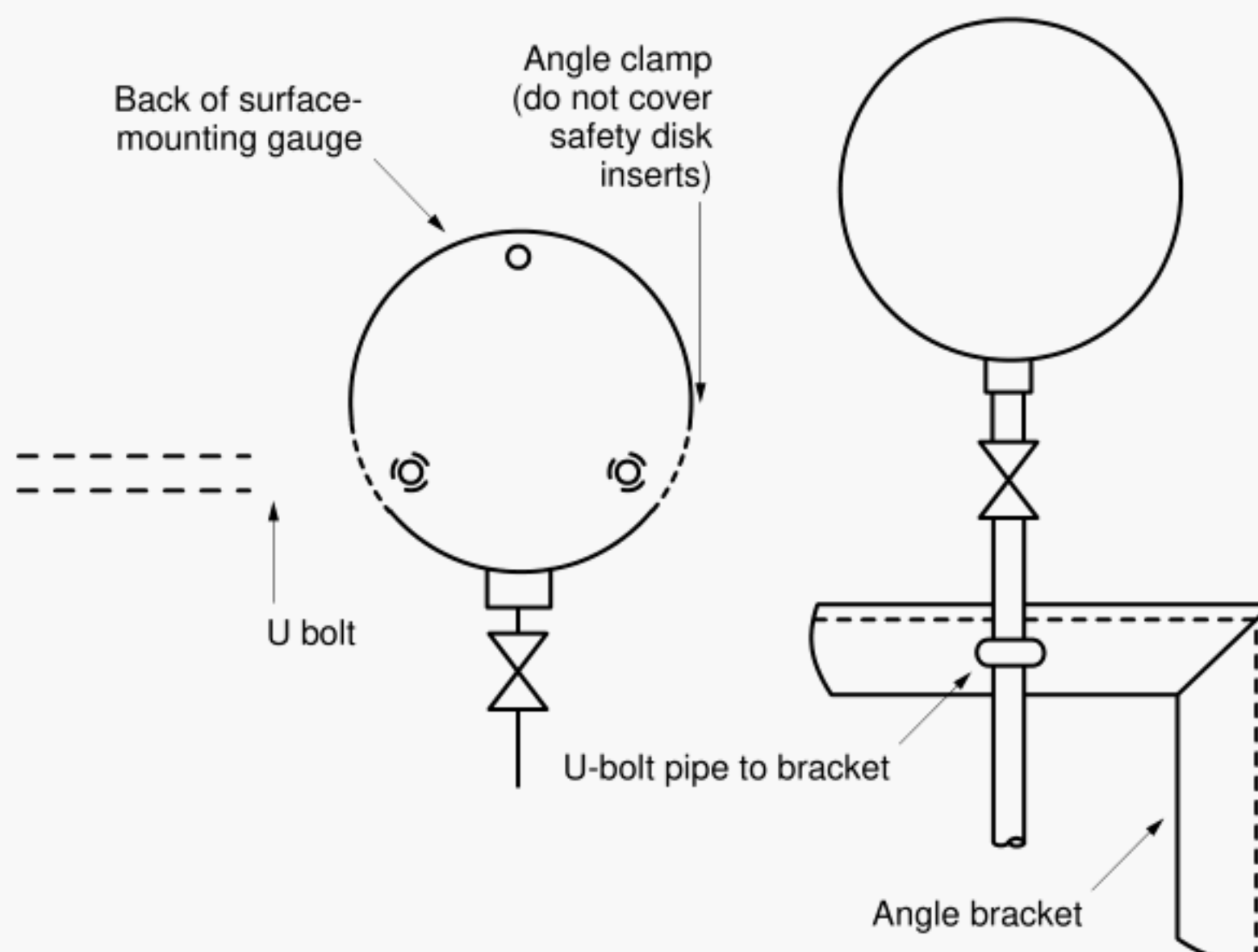


Figure 22—Field-Mounted Gauge Supports

mounted above the process connection, allowing condensate drainage to the process. Siphons protect the gauge from thermal damage and errors due to temperature. Close-coupled siphons are available from most gauge manufacturers (see Figure 23).

4.3.5 CASE MATERIAL AND SIZE

Pressure gauge cases are made of stainless steel, aluminum, or plastic. Plastic-case gauges should not be used in locations where temperature will deform the plastic. Cases in 3½- and 4½-inch sizes are generally acceptable in process fluid service.

4.4 Pressure Transmitters

4.4.1 CONNECTIONS

As discussed in 4.2.8.1, the process connection is generally ¾ inch in size, with the first block valve conforming to applicable process piping specifications. The most common size for instrument connections is ½ inch.

4.4.2 INSTALLATION CONSIDERATIONS

The installation of a pressure transmitter requires careful weighing of a variety of factors. It is important to know the physical characteristics and operating conditions of the process fluid. Following are some guidelines (see Figure 24):

- Impulse piping should be as short as possible.
- Larger, heavier transmitters should be supported by means other than the process connection.
- Placement of taps on the bottom of the line should be avoided because of the possible presence of sediment or scale.
- Transmitters in liquid or condensable-vapor service such as steam should be self-venting (that is, mounted below the process connection, with all lines sloping toward the instrument) to prevent gas from being trapped in the instrument.
- Transmitters in gas service should be self-draining (that is, mounted above the process connection, with all lines sloping toward the process connection) to prevent liquid from being trapped in the instrument.
- The installation must protect the transmitter from both ambient and process temperatures. If the process temperature is outside the transmitter's limits, the following measures can be used to ensure that the temperature at the transmitter is within the manufacturer's specifications:
 - Providing a sufficient length of uninsulated piping to lower or raise the temperature of the process fluid at the transmitter.
 - Purging the transmitter. When purging, piping of sufficient diameter to minimize friction effects should be used (see Section 6).
 - Using a diaphragm seal and capillary to transmit pressure to the transmitter.

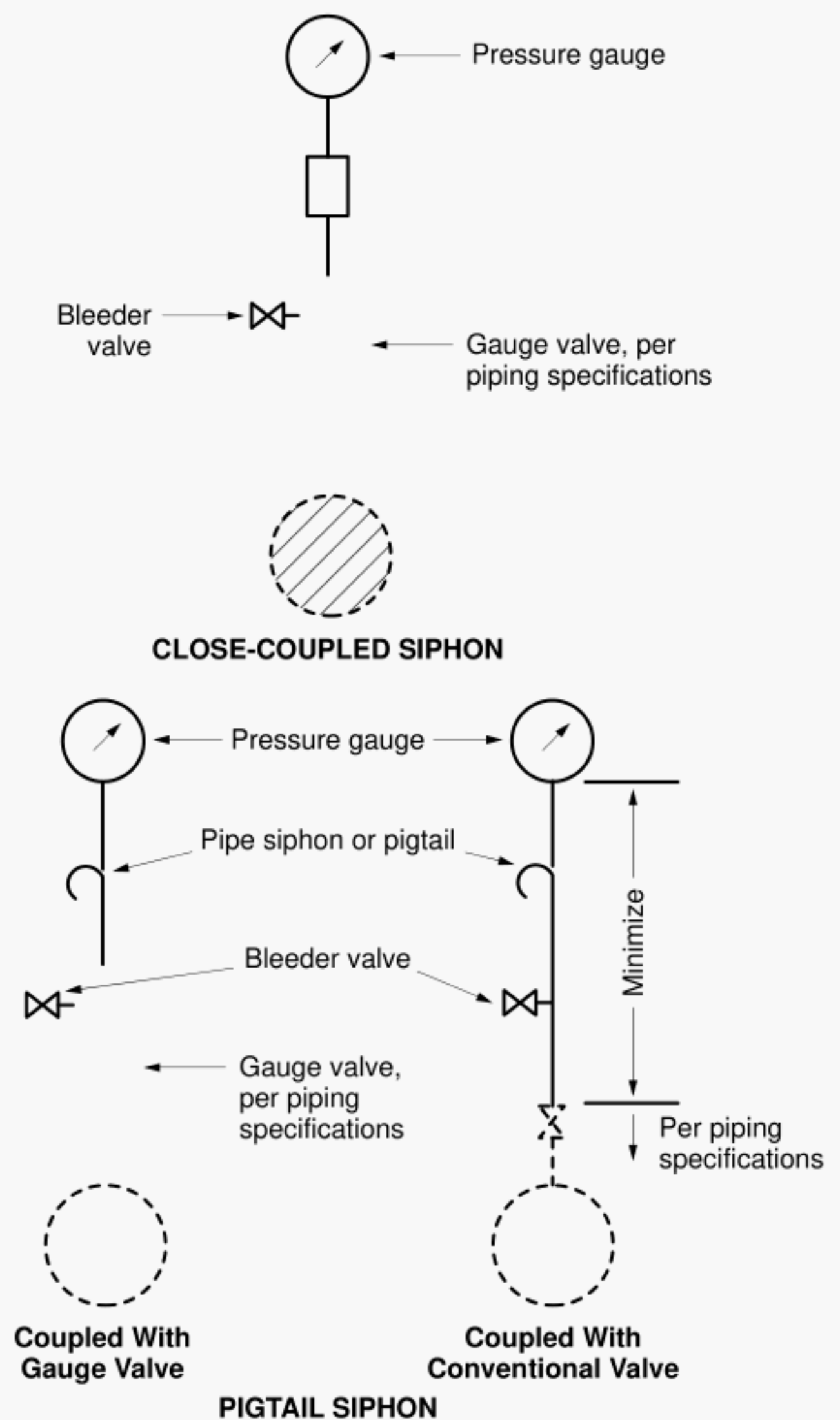
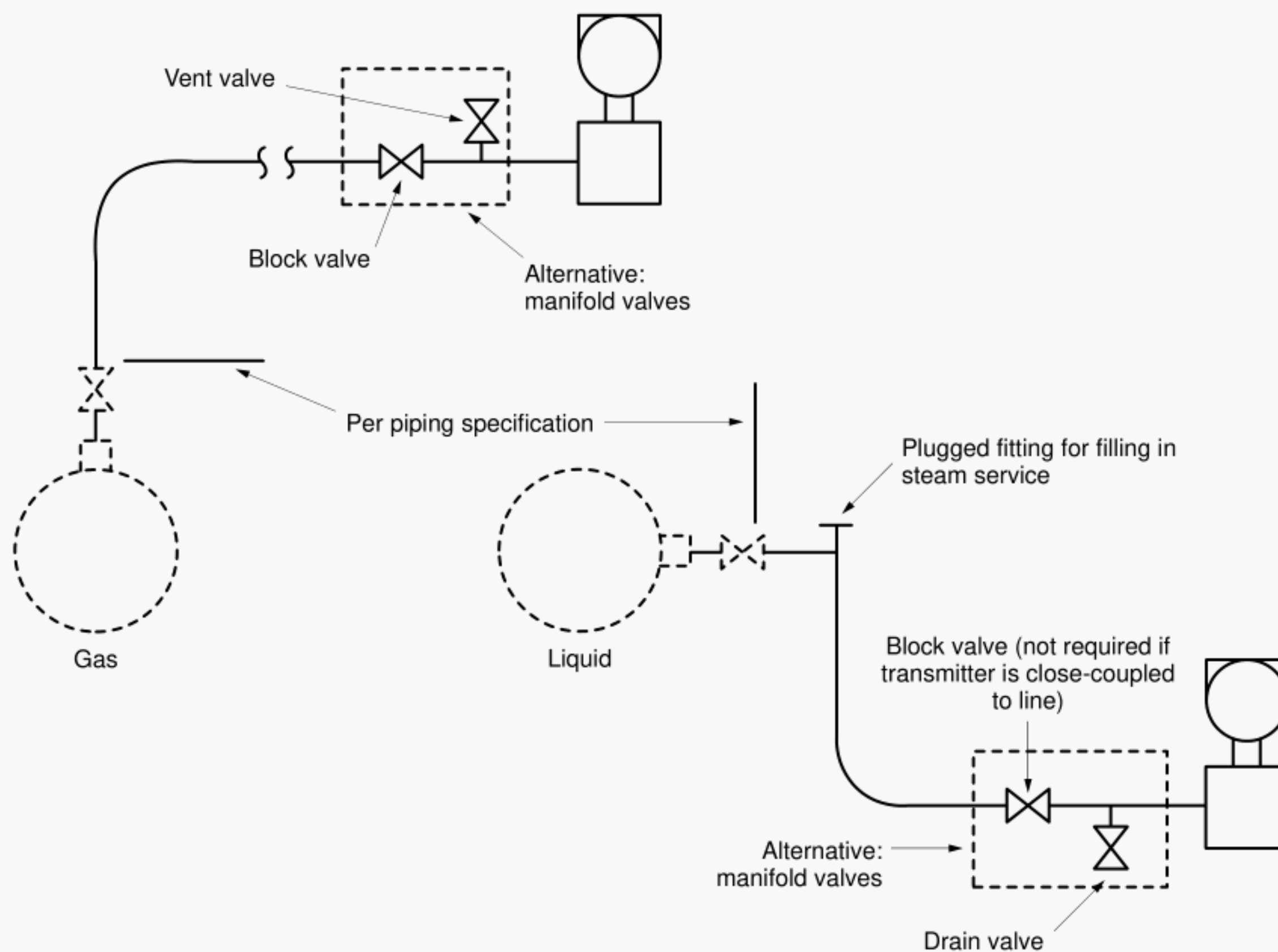


Figure 23—Gauges With Siphon Required in Hot Condensable-Vapor Service

4.4.3 DIFFERENTIAL-PRESSURE TRANSMITTERS

Differential pressure is measured with a differential-pressure transmitter. If purging is necessary for low-differential services, special care should be taken to ensure that the purge rate does not cause erroneous readings (see Section 6; see Figure 25 for an example). A differential-pressure transmitter can be used to measure low gauge pressure by leaving the transmitter's low-pressure connection open to the atmosphere.



Note: Piping should be sloped so that gas condensate drains back into the process line.

Figure 24—Typical Installation of Pressure Transmitters for Gas, Liquid, and Steam Service

4.5 Locally Mounted Controllers and Recorders

4.5.1 CONNECTIONS

The process connection requirements for locally mounted controllers and recorders are similar to those for transmitters (see 4.4.1).

4.5.2 SUPPORTS

In general, instruments should be supported independent of the process connection. Pipe stands at grade and on plat-

form structures are commonly used. Instruments that are to be accessible from a platform should be supported from the platform's structural steel and not from the platform or handrails.

Care should be taken to avoid imposing stresses on the instrument from piping or conduit (see API Recommended Practice 550, Part 1, Section 7).

4.5.3 INSTALLATION CONSIDERATIONS

Many of the installation guidelines for transmitters are pertinent to locally mounted instruments (see 4.4.2).

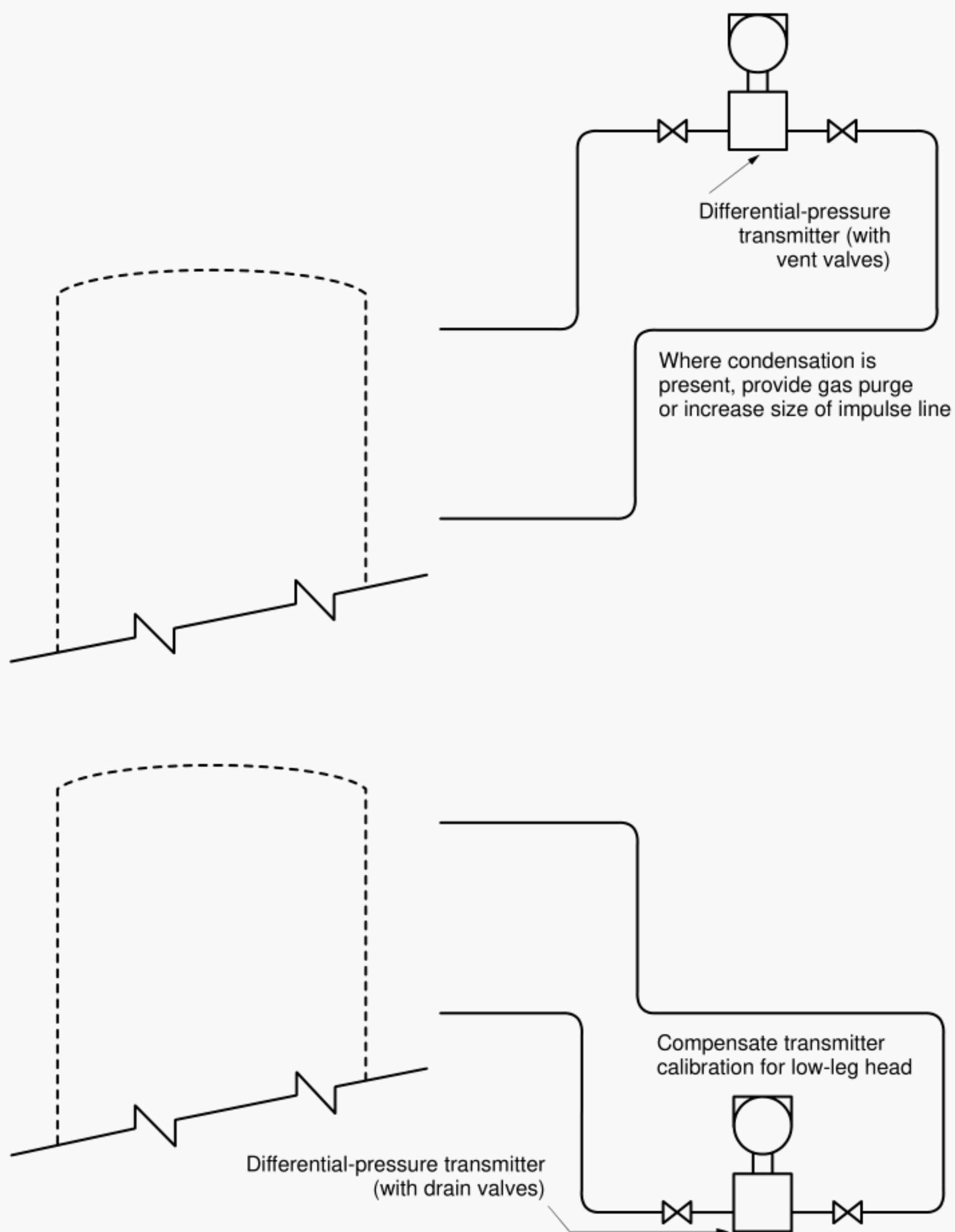


Figure 25—Schematic for Measurement of Pressure Differential Across a Reactor or Section of Tower

SECTION 5—TEMPERATURE

5.1 Scope

This section presents common practices for installation of devices to measure and display temperature in refinery process services and to do the following:

- Display the temperature at the point of measurement.
- Use the temperature for local control of the process variable.
- Transmit the temperature to a remote location for indication, recording, alarm, and/or control at that point.

Included in the discussion are the more common types of measuring devices and accessories: thermocouples, resistance temperature detectors, filled-system instruments, dial thermometers, thermistors, and radiation pyrometers. Thermowells are discussed because of their requirements as a part of temperature systems on most applications. Self-acting temperature controllers, multiplexers, and digital instruments are also included insofar as their use in temperature measurement is concerned. Because transmission systems are discussed in API Recommended Practice 552, temperature transmission is discussed only briefly in this section. Custody transfer temperature measurement is covered in Chapter 7 of the *API Manual of Petroleum Measurement Standards*.

5.2 Thermowells

5.2.1 GENERAL

Direct exposure of temperature-sensing devices to process fluids is usually impractical. Thermowells (see Figures 26–28) are employed in temperature measurement to protect thermal elements and to permit removal of these elements during plant operation in spite of the thermal lag introduced. It is important to maintain good contact between all temperature-sensing elements and the bottom of their wells.

5.2.2 INSERTION LENGTH

The insertion length, U (see Figure 26), is the distance from the free end of the temperature-sensing element or well, up to but not including the external threads or other means of attachment to a vessel or pipe.

5.2.3 IMMERSION LENGTH

The immersion length is the distance from the free end of the temperature-sensing element or well to the point of immersion in the medium whose temperature is being measured. The immersion length required to obtain optimum accuracy and response time is a function of factors such as the type of sensing element, available space, the design of the mechanical connection, and well strength requirements. Optimum immersion depth also depends on heat transfer considerations, as determined by the physical properties of

the measured fluid, the flow velocity, the temperature difference between the measured fluid and the wellhead, and the material and mass distribution of the well and the sensing element.

Insufficient immersion can result in errors because heat will be conducted to or away from the sensitive end of the thermowell. Excess immersion length in high-velocity service can cause thermowells to break.

A thermowell installed perpendicular or at a 45-degree angle to the pipe wall should have a minimum immersion length of 2 inches and a maximum distance of 5 inches from the wall of the pipe. If the thermowell is installed at an angle or in an elbow, the tip should point toward the flow in the process line.

Thermowells installed in lines through which fluid flows at a high velocity may be subject to vibration, which can rupture the well below the mounting. Tapered stems and U lengths established by means of stress analysis are recommended for high-velocity lines (see ASME PTC 19.3).

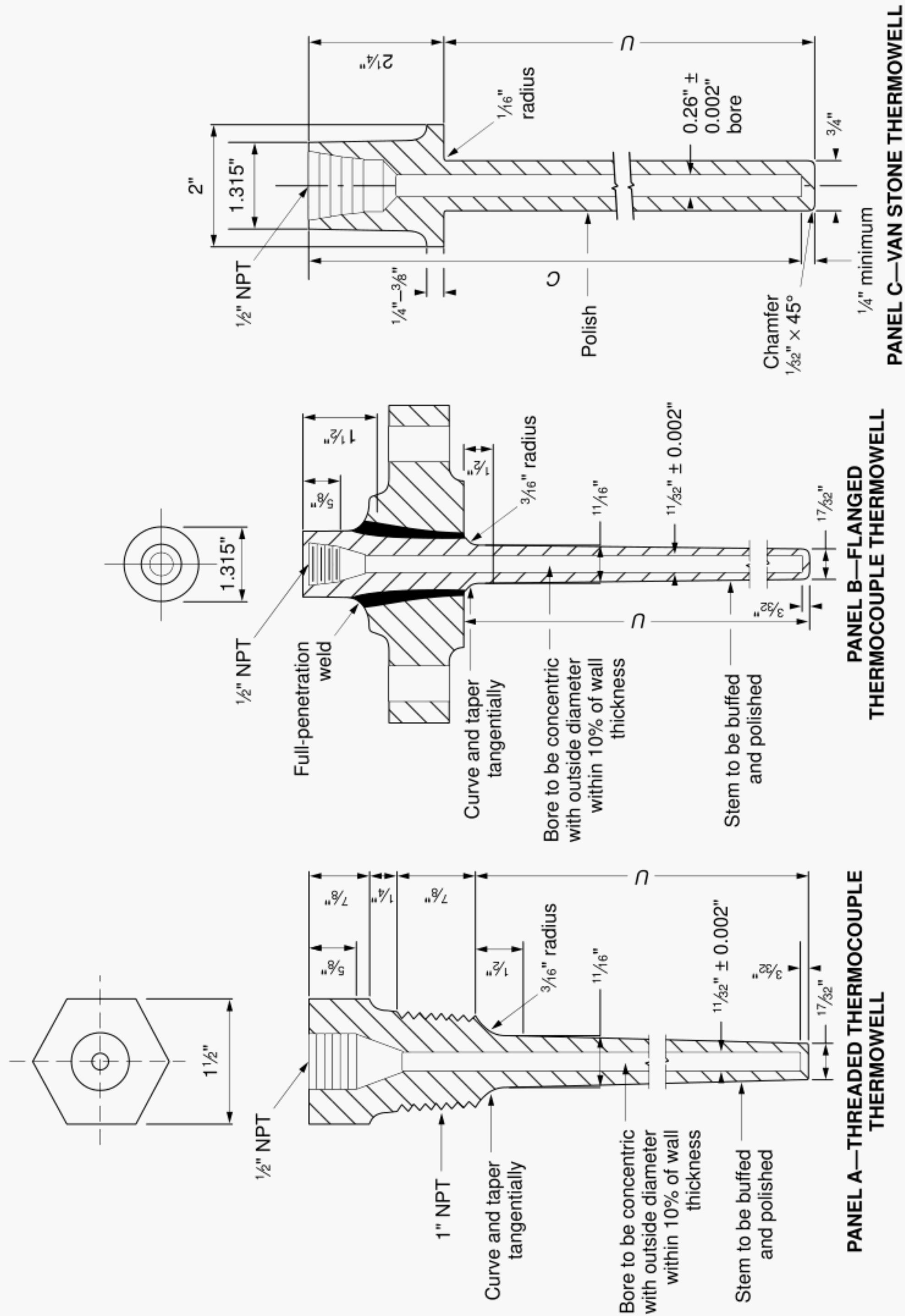
Thermowells should be suitable for the stresses resulting from stream velocity conditions. The wake frequency (commonly referred to as “Strouhal” or “Von Karman trail”) should not exceed 66 percent of the thermowell’s natural frequency. Where the 66-percent requirement results in a non-standard thermowell configuration, all data and parameters affecting the design should be reviewed for alternatives. Refer to the *ASME Performance Test Codes* for more detail on this phenomenon.

5.2.4 MATERIALS

The materials selected for thermowells must be suitable for the temperature and corrosion environment encountered. For general services in which carbon steel piping is normally used, the minimum quality material usually specified is Type 304 or Type 316 stainless steel. Thermowells in certain corrosive services (such as dilute acids, chlorides, and heavy organic acids) require well materials suitable for the specific corrosive media. Thermowells for use in hydrofluoric acid alkylation, catalytic reforming (hydrogen service), hydrocracking, and fluid catalytic cracking units require special engineering attention when materials of construction are selected. Some thermowell manufacturers include material selection guides in their handbooks and catalogs, which serve as useful references.

5.2.5 CONSTRUCTION

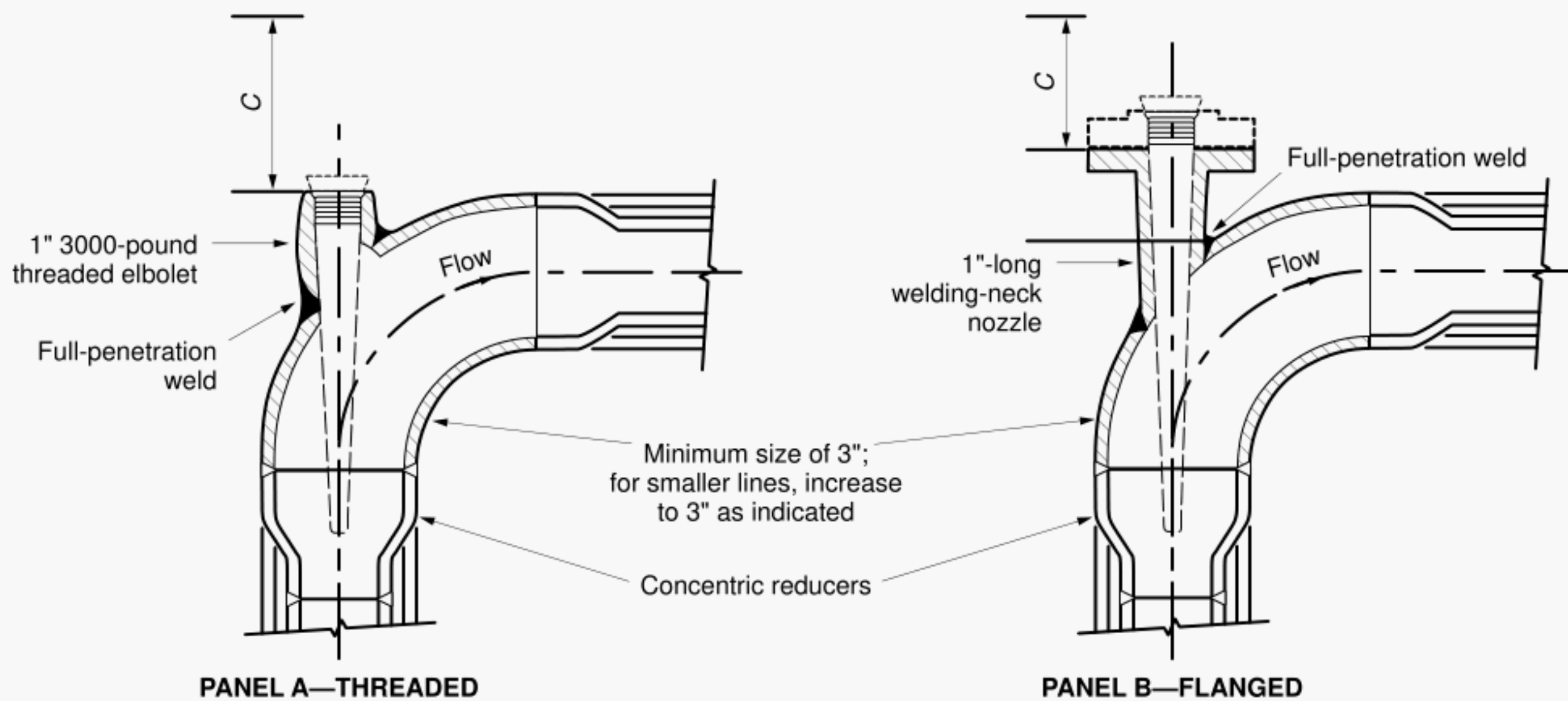
Typical thermowell construction and installation details are shown in Figures 26–28. Thermowells may be screw mounted, as shown in Figure 26, Panel A; Figure 27, Panel A; and Figure 28, Panel A. Van Stone thermowells (see Figure 26, Panel C) may also be used; however, where frequent



Notes:

1. For flanged thermocouples, an ASME B16.5 flange suitable for the thermocouple's rating (see project specifications) should be used. The flange should be furnished and fabricated by the well supplier.
2. For Van Stone thermowells, the 1500-pound pressure class, as specified in ASME B16.5, should be used.

Figure 26—Thermowell Installation



Notes:

1. The *C* dimension should be at least 24 inches to provide clear space for removal of the thermowell.
2. When reducers are installed horizontally, the eccentric type should be used to prevent pockets.

3. Flanges should be in accordance with ASME B16.5.

4. The inside diameter of flanged connections should be at least 1 inch.

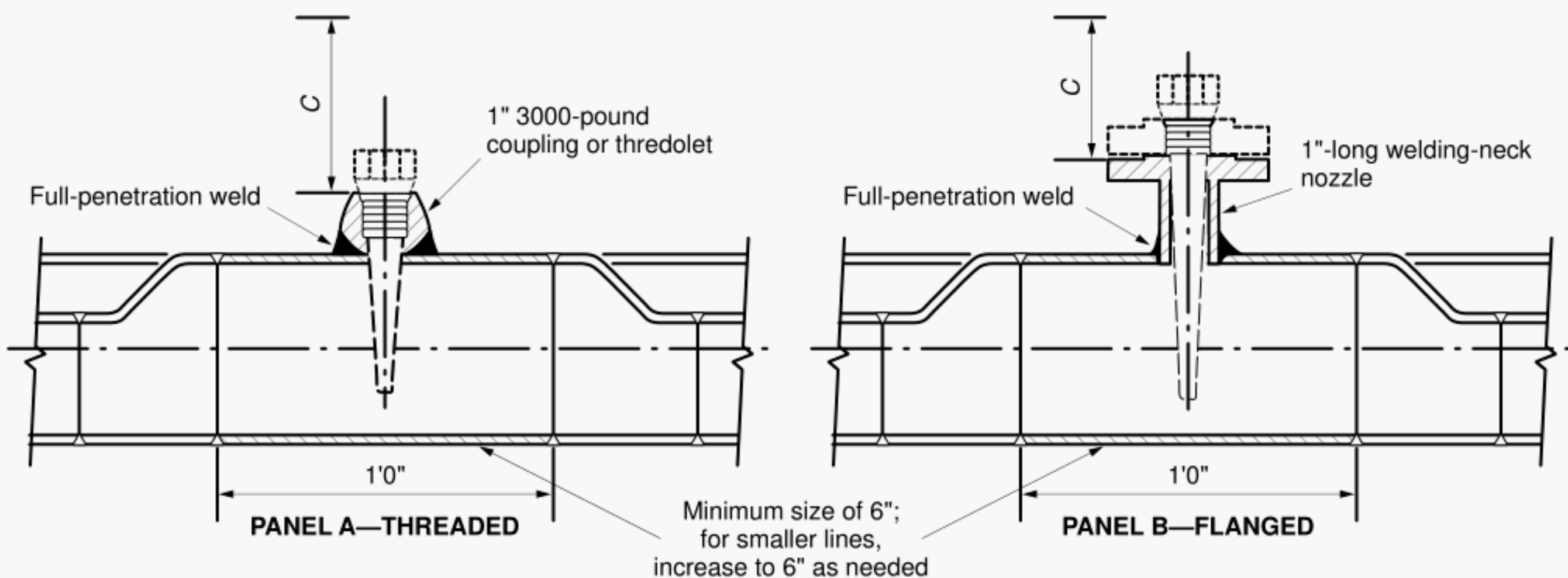
5. Elbow installations are preferred for lines 6 inches and smaller in size.

6. It is preferable for wells to be installed vertically, on top of the pipe. For lines smaller than 3 inches, any elbow installation must be vertical.

Figure 27—Elbow Installation of Thermowells

inspection, special materials (for example, glass coating), temperature cycling, or pressure and temperature limitations require, flange-mounted wells (Figure 26, Panel B; Figure 27, Panel B; and Figure 28, Panel B) are commonly installed in accordance with piping specifications. When experience indicates that rapid temperature response is necessary, thermowells should be constructed with the minimum wall

thicknesses permitted by operating conditions. Spring-loaded thermocouples can be used to ensure that the element seats at the bottom of the well, thus providing improved thermal conductivity to the process fluid. Each thermowell should be stamped with the tag number of its corresponding temperature element.



Notes:

1. The *C* dimension should be at least 24 inches to provide clear space for removal of the thermowell.
2. When reducers are installed horizontally, the eccentric type should be used to prevent pockets.

3. Flanges should be in accordance with ASME B16.5.

4. The inside diameter of flanged connections should be at least 1 inch.

5. Elbow installations are preferred for lines 6 inches and smaller in size.

6. It is preferable for wells to be installed vertically, on top of the pipe. For lines smaller than 3 inches, any elbow installation must be vertical.

Figure 28—Vessel and Line Installation of Thermowells

Table 1—Thermocouple Materials and Temperature Range

ANSI Symbol	Thermocouple Materials	Normal Temperature	
		°F	°C
E	Chromel-Constantan	–300 to 1600	–200 to 900
J	Iron-Constantan	30 to 1400	0 to 750
K	Chromel-Alumel	–300 to 2300	–200 to 1250
R	Platinum, 13% rhodium-platinum	30 to 3000	0 to 1650
S	Platinum, 10% rhodium-platinum	30 to 3000	0 to 1650
T	Copper-Constantan	–300 to 650	–200 to 350

5.3 Thermocouple Temperature Instruments

5.3.1 GENERAL

The thermocouple materials most commonly used in the refining industry are listed in Table 1.

5.3.2 APPLICATIONS

5.3.2.1 General

Temperature instruments that use thermocouples are some of the most generally applied of all temperature-measuring devices. They are applicable for a wide range of temperatures with acceptable accuracy and repeatability. Additional information on applications of these instruments can be found in ASTM STP 470B.

5.3.2.2 Fabrication

Fabrication details for thermocouples are covered in ANSI MC 96.1. The most commonly used thermocouple assemblies are metal sheathed and mineral insulated. A sheathed thermocouple provides increased physical and chemical protection for the thermocouple wires, can be bent or shaped to necessary forms, and allows the junction or sheath to be welded to a surface. These assemblies are made by insulating the thermocouple conductors with a high-purity, densely packed ceramic material (usually magnesium oxide) and enclosing the assembly in an outer metal sheath. Outside diameters range from 0.04 to 0.84 inch (from 1 millimeter to 21 millimeters) using thermocouple wire sizes from 36 gauge up to 8 gauge. Larger wire sizes used in elevated-temperature applications tend to increase the durability of the installation. Sheathing material is available in a variety of stainless steels, nickel-chromium-iron and nickel-copper alloys (for example, Inconel and Monel), titanium, tantalum, platinum, and other workable materials.

Two types of measuring junctions (see Figure 29) are in general use:

- Type A is the standard construction; it has a grounded tip welded or silver soldered to the sheath for fast response.
- Type B has an ungrounded tip (electrically isolated from the sheath) for slower response.

The choice of which type of junction to install is an engineering consideration beyond the scope of this document. Plant practices and manufacturers' literature are good sources of information.

5.3.2.3 Installation

Thermocouples are generally installed in thermowells, as discussed in 5.2. To minimize temperature lag (response time), the thermocouple must be in contact with the bottom of the well. The correct type of extension wires for the particular thermocouple must be used to connect the thermocouple to the instrument. For information on thermocouple extension wires, see 5.3.5.

Metal-sheathed, mineral-insulated thermocouples are sometimes installed with the thermocouple head separated from the thermowell. An example of this type of installation is shown in Figure 30.

There are applications in which metal-sheathed, mineral-insulated thermocouples are sometimes installed as bare elements without thermowells, usually to obtain faster response. This type of installation should only be used where the process fluid or conditions present no risk to personnel during removal of the element. Where thermocouples are installed without thermowells, special wiring tags of a distinct color and durable material should be attached as a warning to maintenance personnel.

Metal-sheathed thermocouples provide longer life and improved long-term accuracy compared with bare-wire thermocouples. Metal-sheathed thermocouples have generally

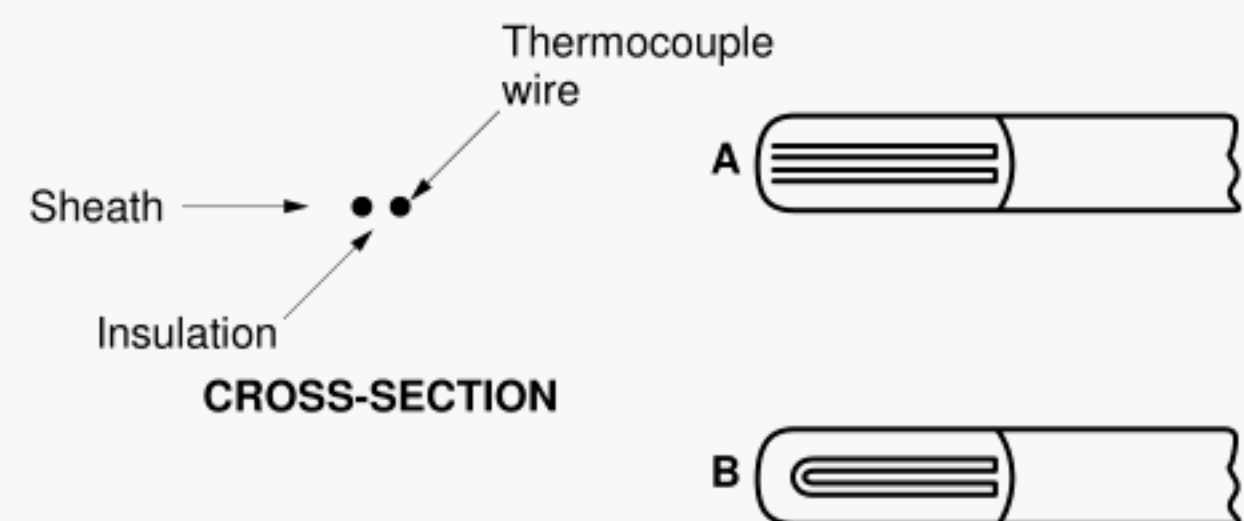
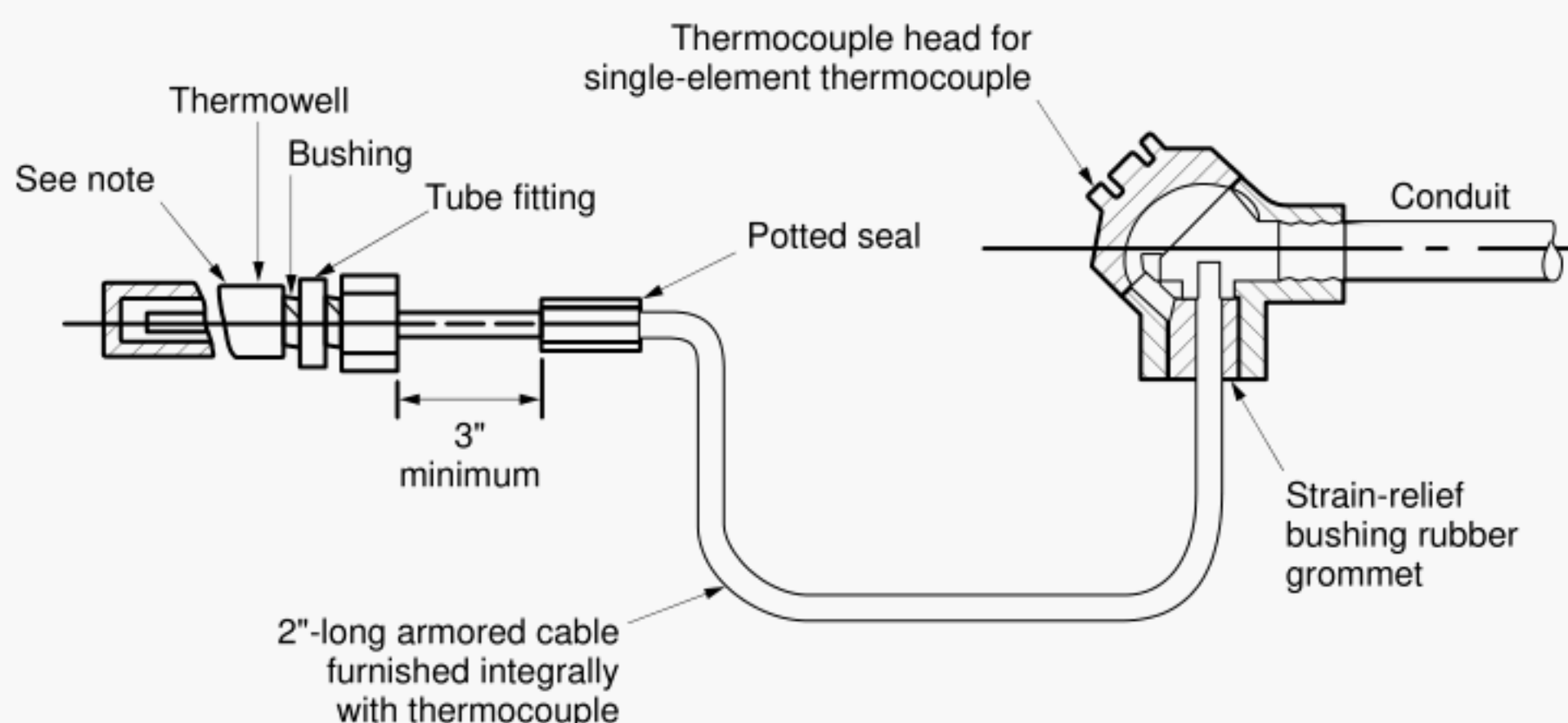


Figure 29—Metal-Sheathed, Mineral-Insulated Thermocouple Assemblies



Note: A male tubing fitting should be provided for the thermocouple to pass through. The ferrule and nut should be installed, then the thermocouple should be pushed to the bottom of the well, and then the tubing nut should be tightened to secure the thermocouple in the well.

Figure 30—Sheathed-Type Thermocouple and Head Assembly

been more satisfactory in applications that require long installation lengths, such as reactors.

For field installation, the thermocouple should not be directly connected to a rigid conduit; a flexible connection should be used, as shown in Figure 31.

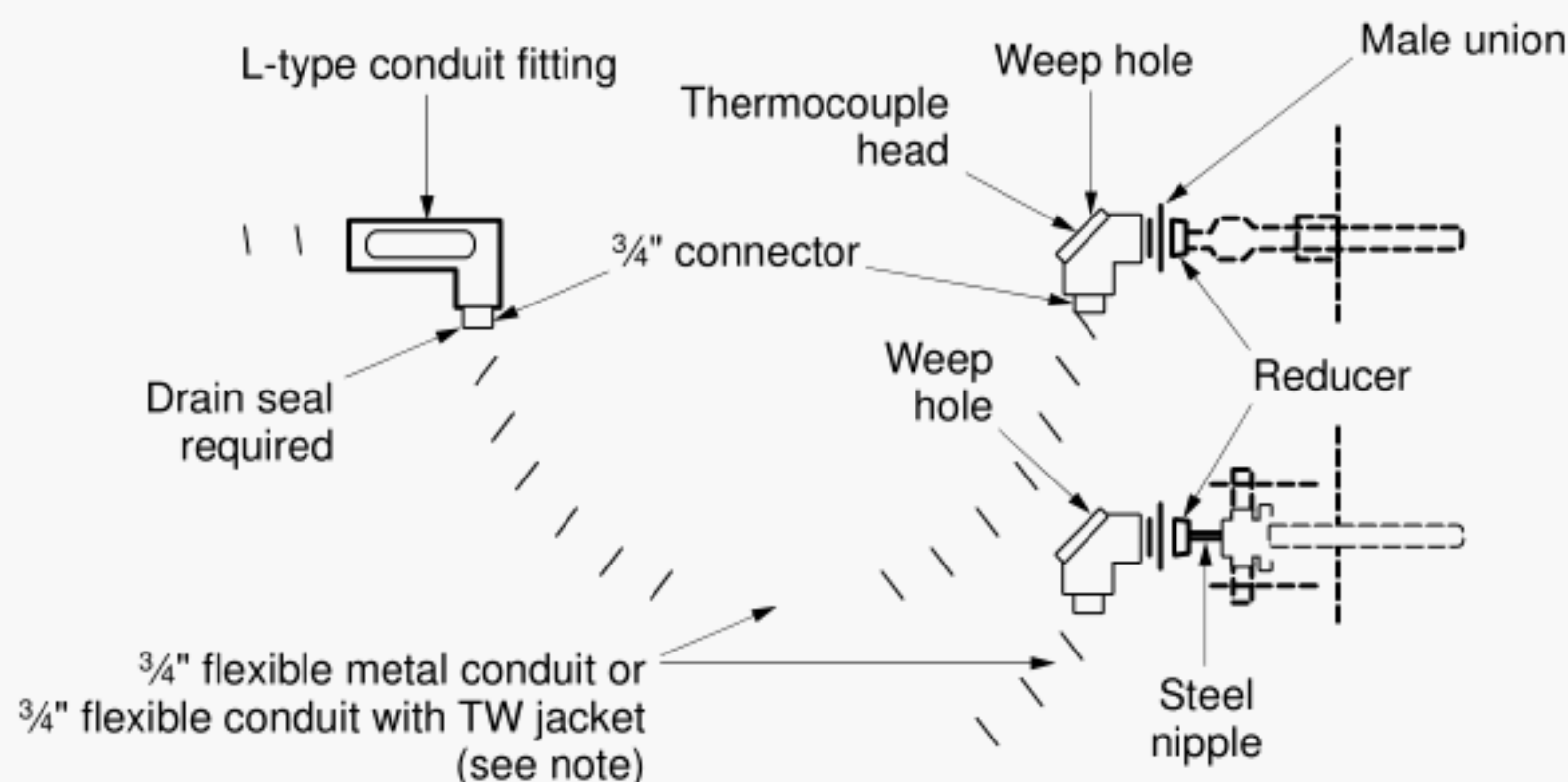
Particular attention should be paid to the installation so that it is possible to vent process fluid from the thermowell and conduit in the event of a failure. A seal-off with a drain at the thermocouple end of the conduit and a seal-off with a drain at the point of entry to the control room provide a double block and bleed in case the thermowell fails and process fluid or gas enters the conduit (see Figure 30).

The choice of grounded or ungrounded thermocouples is dictated by the application. For grounded thermocouples, care should be taken to guarantee that a suitable ground is provided at the thermowell. Regardless of the type used for measurement, grounding should only be done at one point.

5.3.3 TUBE—SURFACE TEMPERATURE MEASUREMENT

A special application of thermocouples is measurement of the temperature of the skin or tube-metal surface of furnace tubes. Such installations require careful attention to ensure that the thermocouple is properly attached to the tube and is shielded from furnace radiation. Care must be exercised to minimize mass addition at the point of measurement. The addition of mass may result in slower response time and potential errors in measurement. Gaps between the tube wall and the thermocouple junction should be minimized. Many companies have their own standards for this application. These installations can be costly, are complex, and may not be entirely reliable.

One design for attaching this type of thermocouple to heater tubes is shown in Figure 32. Other designs also pro-



Note: Where TW-jacketed flexible steel conduit is used, it should be vented to relieve pressure in case the thermowell fails.

Figure 31—Thermocouple-to-Conduit Connections

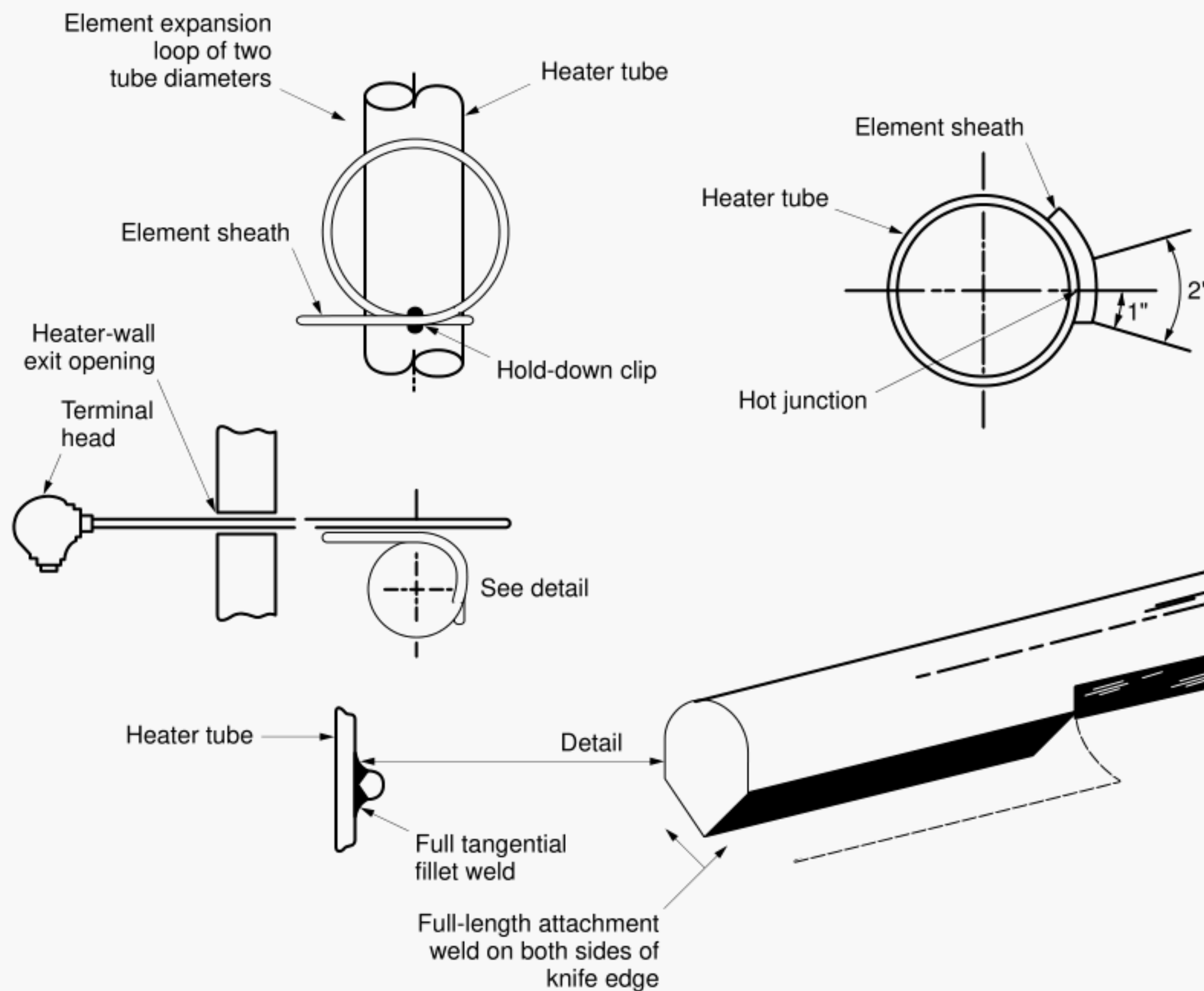


Figure 32—Knife-Edge Tube-Surface Thermocouple for Heater Tube

vide satisfactory service. Thermocouples of this type are also used to measure surface temperatures of the external wall of reactors and other vessels. They require the same care as do the furnace-tube surface-temperature installations.

5.3.4 FIREBOX TEMPERATURE MEASUREMENT

Thermocouples in fireboxes require some special handling because of the wall construction. Figure 33 shows a typical installation.

5.3.5 EXTENSION WIRES

Thermocouple extension wires must have the same electromotive-force temperature characteristics as the thermocouple to which they are connected. This will, in effect, transfer the reference junction at the end away from the thermocouple to a point where its temperature is reasonably stable and where the effect of temperature variations can be compensated for. The use of incorrect extension wires will cause errors in temperature readings by creating extra thermocouples at the terminal blocks or in the instrument.

Thermocouple extension wires, which are available either in pairs or in bundles with multiple pairs, should be installed as described in API Recommended Practice 550.

Materials for thermocouple extension wires are listed in Table 2. For limits of error associated with extension wires, refer to ANSI MC 96.1. The sizes normally used for extension wire either singly or in pairs are 14, 16, and 20 American wire gauge (AWG), with 16 AWG being the most common size used. When bundled and reinforced to provide strength for pulling, sizes of 20 AWG and smaller may be used.

5.3.6 SIGNAL CONDITIONING

5.3.6.1 General

Signal conditioners receive input signals from one or more sensors and generate a corresponding output signal in a form that can be accepted by monitors or controllers.

Instruments typically use solid-state digital electronic amplifiers or microprocessors that linearize or characterize the thermocouple inputs to match the calibration tables. Input impedance is usually very high.

Thermocouple-burnout (open-circuit) protection should be provided and is usually a part of the amplifier design. Some designs for digital systems provide continuity checking by generating pulses that, when sent down the thermocouple lines, could affect multiplexing signals.

The amplifier should have high common-mode rejection to prevent conversion of common-mode to normal-mode voltage. This is extremely important for high-speed measuring circuits but should not be neglected for low-speed circuits.

It is normal practice to provide dual thermocouples for control loops.

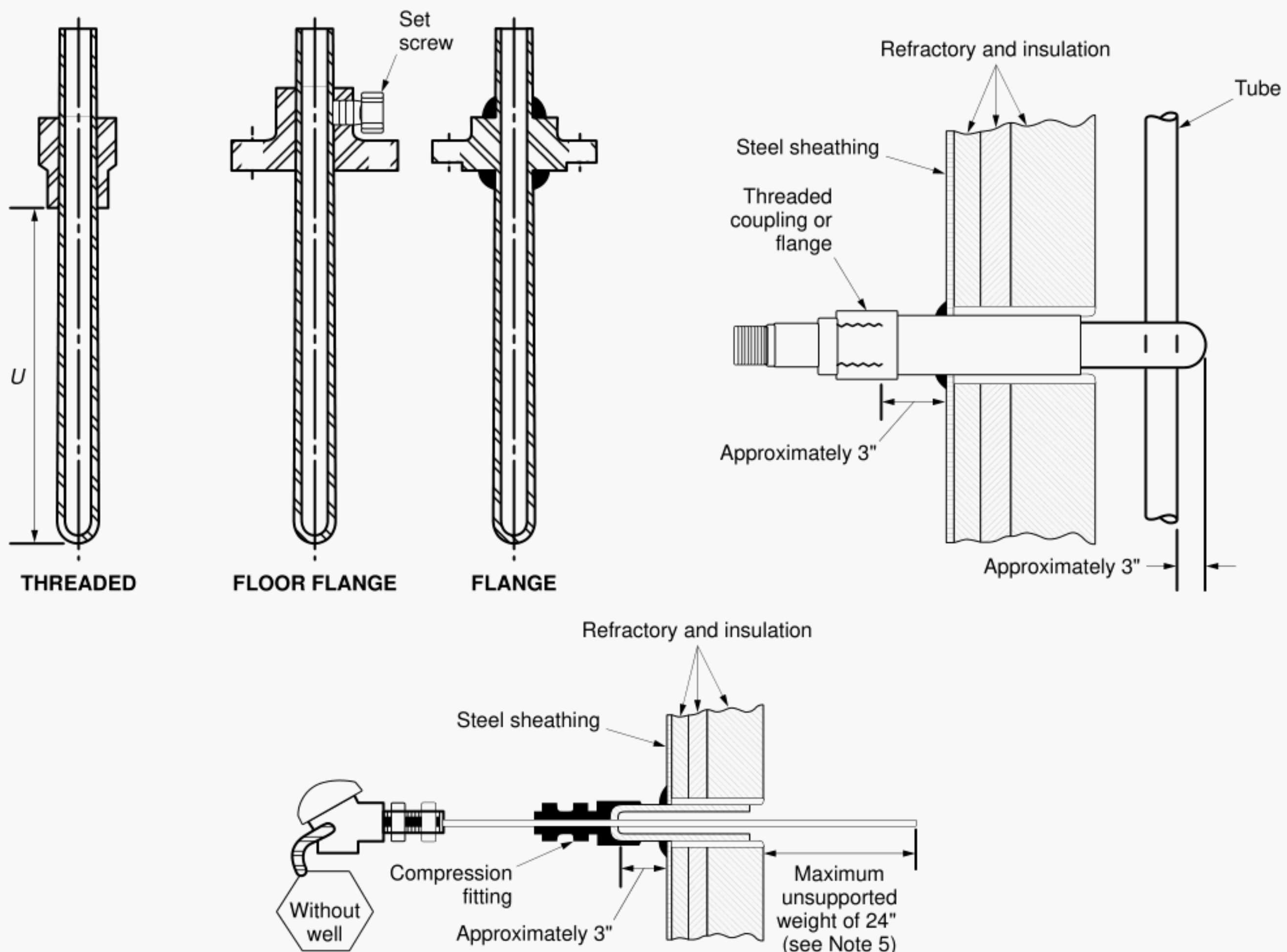
5.3.6.2 Thermocouple Transmitters

Thermocouple transmitters can be mounted in the thermocouple head or in the control room. Two types of field-mounted transmitters are available. One is mounted directly on the thermowell, and one is mounted remotely from the thermowell. Thermocouple transmitters mounted on the

thermocouple head may have limitations with regard to ambient-temperature effects, accessibility, vibration, and grounding. Transmitters mounted remotely from the thermowell offer advantages in overcoming these difficulties; receiver gauges or meters can be used for local indication.

5.3.6.3 Multiplexing

Multiplexing systems gather many thermocouples (or other sensors) together into one or more units. The temperature of the reference junction is measured in the multiplexer unit. The master unit selects one input to be measured, by either random or programmed access. The selected input is converted to a digital signal at the field unit. The master unit receives the signal; performs linearization, reference-junc-



Notes:

1. See API Recommended Practice 550, Part III, Table 1-1, for materials.
2. Materials outside of the firebox may be other than those specified in API Recommended Practice 550, Part III, Table 1-1.
3. The thermocouple should have an outside diameter of 0.500 inch and a wall thickness of 0.120 inch. The thermocouple should have a MgO-insulated, 14-gauge 90Ni-10Cr thermocouple wire with a Type 446 stainless

steel sheath or should be of a material listed in API Recommended Practice 550, Part III, Table 1-1.

4. The head end of the thermocouple should have 2 inches of exposed wire. The mineral insulation should be removed to a depth of at least $\frac{1}{4}$ inch and potted with compound.

5. The 24-inch maximum immersion length does not apply to top-entering installations.

Figure 33—Typical Firebox Thermocouple Installations

Table 2—Thermocouple Extension-Wire Materials

ANSI Symbol	Thermocouple Materials	Extension Wire Materials
EX	Chromel-Constantan	Chromel-Constantan
JX	Iron-Constantan	Iron-Constantan
KX	Chromel-Alumel	Chromel-Alumel
SX	Platinum, 10% or 13% rhodium-platinum	Copper-copper-nickel alloy
TX	Copper-Constantan	Copper-Constantan

tion compensation, and scaling; and displays the temperature or provides a digital signal for input to a control system, process computer, or other device. Multiplexing of thermocouples and resistance temperature devices is generally used for monitoring applications but is not recommended for control because of common-mode failure and limitations on input scan speed.

5.3.7 INPUT CIRCUITS

The reference junction, sometimes called the cold junction, is the junction of a thermocouple circuit that is held at a known stable temperature.

If the temperature of one of the junctions is at a known temperature, T_0 , such as that of melting ice, the measurement of electromotive force and hence of $\Delta T = (T_x - T_0)$ makes it possible to determine the temperature of the other junction, T_x , by algebraic addition of ΔT and T_0 , ($T_x = T_0 + \Delta T$). The reference junction is usually located in the transmitter, multiplexer, or receiver instrument. Electronic or microprocessor-based temperature transmitters provide reference-junction compensation within the transmitter itself.

In instances where especially accurate temperature measurements are required or where the temperature instrument is subjected to varying temperatures, the reference junction may be external. In addition, when a number of very long leads are required, a noncompensating cable may be used and a reference-junction compensation device may be located at the termination point of the conventional extension wire. Such external reference junctions may be installed in an enclosure where the temperature is thermostatically controlled. Note that the accuracy of temperature measurements is no better than the constancy of the reference-junction temperature or its compensation in the instrument.

5.4 Resistance Temperature Measurement

5.4.1 APPLICATION

Resistance temperature measurement can provide more accurate measurement of temperature than is possible with thermocouple installations. Accordingly, resistance units are used in many installations where their higher accuracy is warranted, such as in measurement of low differential tem-

peratures. To obtain the higher accuracy and sensitivity inherent in a resistance system and to minimize thermal lag, the optimum thermowell dimensions (for the particular resistance element) must be employed to maintain good contact between the resistance element and the well. For this reason, wells for resistance elements are frequently provided with resistance bulbs as matched units.

Resistance temperature measurement can be used in the extreme range from -450°F to $+1800^\circ\text{F}$ (-270°C to $+980^\circ\text{C}$) and in the practical range from -420°F to $+1500^\circ\text{F}$ (-250°C to $+800^\circ\text{C}$).

5.4.2 RESISTANCE TEMPERATURE DEVICES

Resistance temperature devices (RTDs) operate on the principle of change in electrical resistance on the wire as a function of temperature. Two types of wire are generally used in resistance elements: Nickel is used for temperatures up to 600°F (315°C), and platinum is used for temperatures up to 1500°F (800°C). A third type, copper, is used in large motor windings for temperatures up to 300°F (150°C).

Resistance temperature elements are available in many configurations, the most common type being a tip-sensitive construction. Most resistance elements used in the petroleum industry are mounted in a thermowell. When rapid response times (5–6 seconds) are required, the sheath can be removed and the element used bare in the thermowell.

The use of transmitters, multiplexers, and microprocessors outlined in 5.3.6.2 and 5.3.6.3 is also applicable to RTDs. The precautions and practices applicable to thermocouples are also applicable to RTDs, with two exceptions:

- Ordinary copper wire is used to connect the readout device to the sensor. The most commonly used configuration provides a one-wire connection to one end and a two-wire connection to the other end of the sensor. This compensates for resistance and temperature change in the lead wire.
- The reading is absolute, so a reference junction is not needed. Elements that conform to one of two different curves are available: On the European (DIN) curve, $R = 0.00385$ ohms per ohm per degree Celsius, and on the American (SAMA) curve, $R = 0.00392$ ohms per ohm per degree Celsius. The type of curve that is applicable should be included when senders and receivers are specified. Both curves are based on a sensing-element resistance of 100 ohms at 0°C .

5.4.3 EXTENSION WIRES

The individual extension wires (usually three) from the resistance element may terminate in a connection head or quick-disconnect fitting or extend directly to the measuring unit. A connection head is usually employed, and the wires are frequently run in a three-wire cable to the board-mounted resistance-temperature-measuring instrument. The wire normally used is 18 AWG stranded copper.

Where multiple installations of resistance elements are in place, the wires can be run to a field terminal strip. A multi-conductor cable can then be used to bring the signals into the control panel. The wire in the multiconductor cable may be 20 or 22 AWG; however, for long distances, the manufacturer should be consulted regarding allowable wire resistance. The number of junctions or terminations in the lead wire should be kept to a minimum. Refer to 5.3.6.3 for the use of multiplexers with transmission systems.

5.4.4 RESISTANCE TRANSMITTERS

Attaching resistance elements to locally mounted converters allows use of standard transmission signals and offers more flexibility in receiver equipment. Refer to 5.3.6.3 for multiplexer applications.

5.5 Dial Thermometers for Local Temperature Measurement

Dial thermometers are the most common thermometers in industrial use. They are frequently of the bimetallic type with circular dials and are available in a wide range of temperature scales and styles. Dial thermometers that use filled systems are also available (see 5.6). The most common type has an angle orientation. Care should be taken to ensure readability of the dial from a convenient location while protecting it from damage by falling objects and the like. Some manufacturers offer a version that can be adjusted to various angles. For applications at temperatures below -22°F (-30°C), it may be desirable to use a filled-system type. Refer to manufacturers' catalogs for guidelines on the use of such systems.

5.6 Filled-System Temperature Instruments

5.6.1 GENERAL

A filled thermal system is a closed system that contains a fluid fill (the temperature-sensitive medium) and is composed of a bulb, an expansible device (for example, Bourdon tube, diaphragm, capsule, bellows), and a capillary tube operatively connecting the two. Special attention should be paid to bulb insertion length to ensure that the entire sensitive length is placed in the active zone.

5.6.2 APPLICATIONS

The use of filled-system devices is limited by the capillary tubing that may be employed and the maximum temperature

to which the bulb may be exposed. Systems with compensation are built to self-adjust for changes in temperature either of the case or of the capillary and case. This self-adjustment assures accurate measurement of the temperature where the bulb is located. Dimensional, functional, and physical characteristics vary depending on the manufacturer. Application information and the classes of thermal systems that are in general use can be found in manufacturers' catalogs.

5.6.3 SELF-ACTING TEMPERATURE REGULATORS

Where precise control is not essential, self-acting temperature regulators are frequently used. These devices use thermal expansion systems and direct-operated valves. In operation, an increase in temperature expands the liquid in the system and thereby operates the valve. Many different fluids are used, and bulb sizes and filling fluids vary with the temperature range. As with other temperature-sensing instruments, bulbs should be protected by thermowells.

Valve operators are in bellows form. The bellows may operate either a valve or a pilot valve that controls line fluid for actuating power to operate the main valve. Temperature indication in the form of a dial mounted on top of the valve and operated by the same thermal system is available from some manufacturers. Some form of temperature indication is always desirable with these self-contained devices.

5.6.4 TEMPERATURE TRANSMITTERS

Temperature transmitters may use any one of several types of filled systems, together with pneumatic transmitters and amplifiers, to convert the measured temperature to an air signal.

5.6.5 INSTALLATION GUIDELINES

In all installations of filled-system temperature instruments, it is necessary to protect the bulb and capillary tubing from mechanical damage. It is usually desirable to use armored capillary tubing and to support the tubing run between the bulb and the controller or transmitter to protect it from accidental damage. The capillary tubing should not be cut, opened, or pinched in any manner. For safety purposes, the vent hole on the top of the bulb packing gland should be free from obstructions.

5.7 Radiation Pyrometers

Radiation pyrometers are special instruments used in fired-heater service in refineries, petrochemical, and synthetic fuel plants. Their normal range of use is between -20°F and 7000°F (-30°C and 3900°C). They are nonlinear in output and have an accuracy of about 2 percent. There is no easy way to calibrate the units. They detect high temperatures and offer the advantage of rapid response and noncontact measurement.

A radiation pyrometer measures the temperature of an object optically, without physical contact, by determining its emitted energy. Every object emits radiant energy; the intensity of this radiation is a function of the object's temperature. Infrared radiation is measured in most applications, but ultraviolet radiation is measured in some instances.

In refinery applications, most radiation pyrometers used are used in the high-temperature range. Since these are special applications, the user should work closely with the manufacturer. Purge assemblies may be required for cooling and for keeping the optical lens clean. A typical installation is shown in Figure 34.

If the radiation pyrometer is to measure absolute temperature, the effective emissivity (the emissivity of the target material in the spectral range of the radiation pyrometer) must be determined. This can be done indirectly by applying the radiation laws of physics or experimentally by characterizing the material at a known temperature. Target nonuniformities such as significant temperature changes in the material, the nonhomogeneous nature of some materials, or a basic product change all represent cases in which an absolute change in effective emissivity is exhibited.

When a properly designed industrial instrument is used, background radiation effects are not a detrimental factor as long as the infrared field of view covers only the target area. Reflection from the background area should be minimized to reduce spurious effects of radiant energy from sources other than the target. Infrared instruments are designed to minimize these background conditions, but energy overlays in the electromagnetic spectrum cannot be completely eliminated without impairing the accuracy and performance of the instrument.

Optical pyrometers are radiation pyrometers that operate within the visible spectrum. They usually rely on visual comparison of a filtered view of the target with an internal reference. The subject surface must be hot enough to give off visible radiation, typically above 1400°F (760°C). In applications where infrared or optical pyrometers are used, errors may be introduced if the target surface reflects radiation from other hotter surfaces, including radiation from direct sunlight. Errors may also be introduced if the path is partially obstructed by absorbing materials such as fumes, smoke, or glass.

SECTION 6—PROCESS AND ENVIRONMENTAL PROTECTION

6.1 Scope

This section describes recommended techniques for protecting instruments from adverse process and ambient environments. These techniques include sealing, purging, and heating. Fireproofing is not included in the scope of this doc-

ument; refer to API Publication 2218 for practices related to fireproofing instrumentation.

A *seal* can be a mechanical barrier between the process and the instrument, or it can be a section of piping filled with process fluid or an immiscible seal fluid.

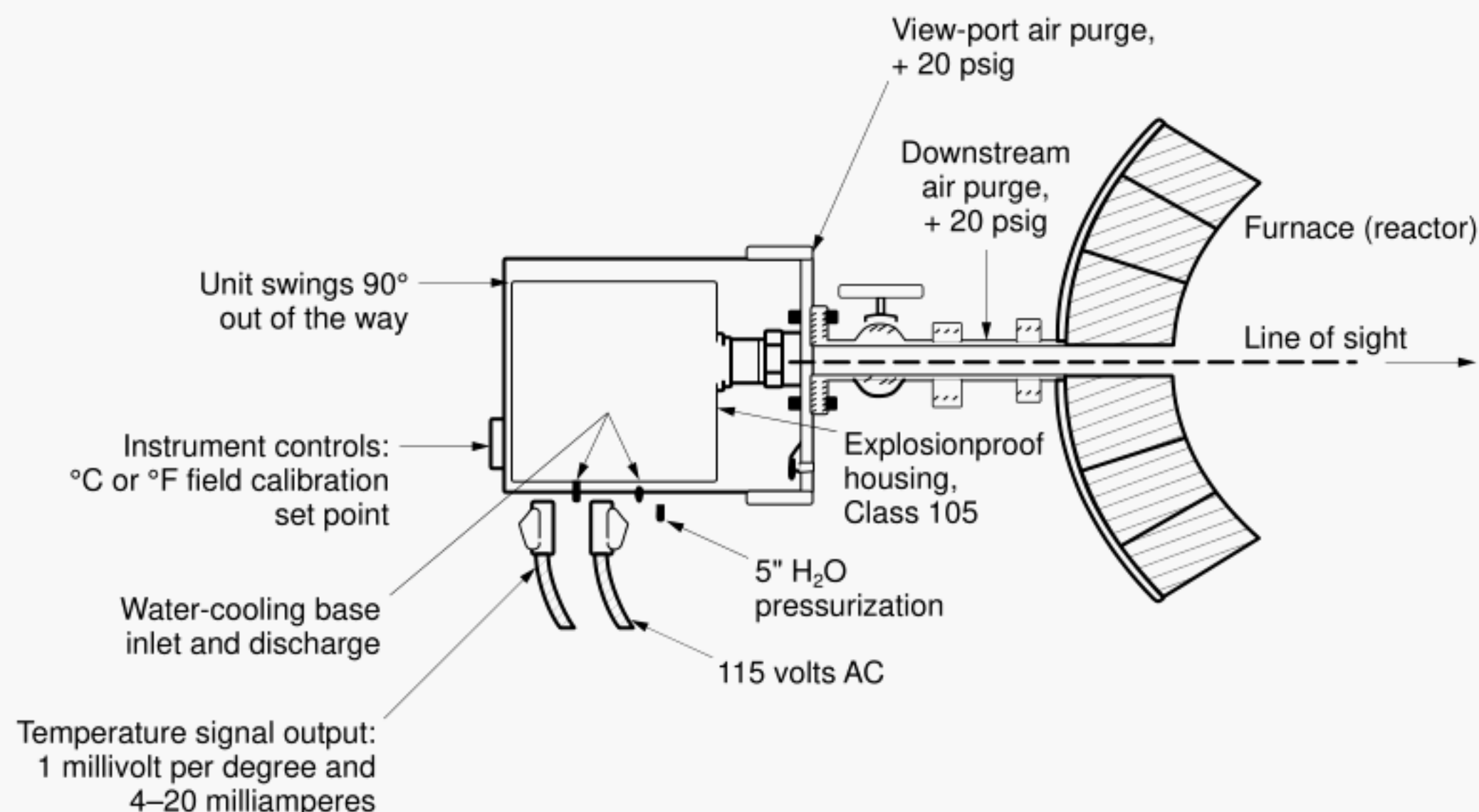


Figure 34—Typical Radiation Pyrometer Installation

A *purge* can be either gas or liquid. Since there is a constant flow of purge material entering the process, care must be taken to ensure compatibility of the purge fluid with the process.

Heating is used to prevent the fluid between the process and the instrument from freezing or otherwise becoming too viscous to flow easily. The heat can come from the process or from steam or electrical tracing.

These techniques are typically applied to pressure gauges, pressure transmitters, differential-pressure transmitters, and the piping that connects these instruments to the process. Analyzers may require specialized heating techniques and are discussed in API Recommended Practice 555.

6.2 General

To obtain the reliability expected of a refinery installation, it is important that process and environmental protection of the instruments be considered early in the project. The basic requirements (heating, sealing, and purging) should be defined on the piping and instrument diagram or otherwise documented.

Most of the transmitters currently available are designed with measurement elements that have little displacement over the measurement range. These should be used whenever a protection system is required.

6.3 Seals

6.3.1 DIAPHRAGM SEALS

Diaphragm seals are used when the process fluid must be positively isolated from the measuring instrument. They are generally used in slurry service and when the process fluid is toxic or corrosive or at elevated temperatures. They can also be used to reduce heating requirements when freezing or high viscosity is a problem.

Pressure-gauge and pressure-switch seals (see Figure 35) usually consist of a diaphragm and a diaphragm holder into which the instrument is connected; a seal fluid is enclosed in the chamber between the diaphragm and the gauge. The holder, diaphragm, and gasket materials are selected to be compatible with the process fluid. The diaphragm is generally welded into the holder, but it may also be clamped and gasketed. The seal fluid should be nonflammable, have low vapor pressure and thermal expansion, and in the case of diaphragm rupture, be compatible with and noncontaminating to the process.

Seals for pressure and differential-pressure transmitters are available in a variety of configurations. A common style is a diaphragm mounted in a wafer, clamped between piping flanges, and connected to the transmitter with an armored capillary (see Figure 36). This style, which uses two seals, is used for flow metering and level measurement in vessels under pressure or vacuum. In some applications, capillaries can

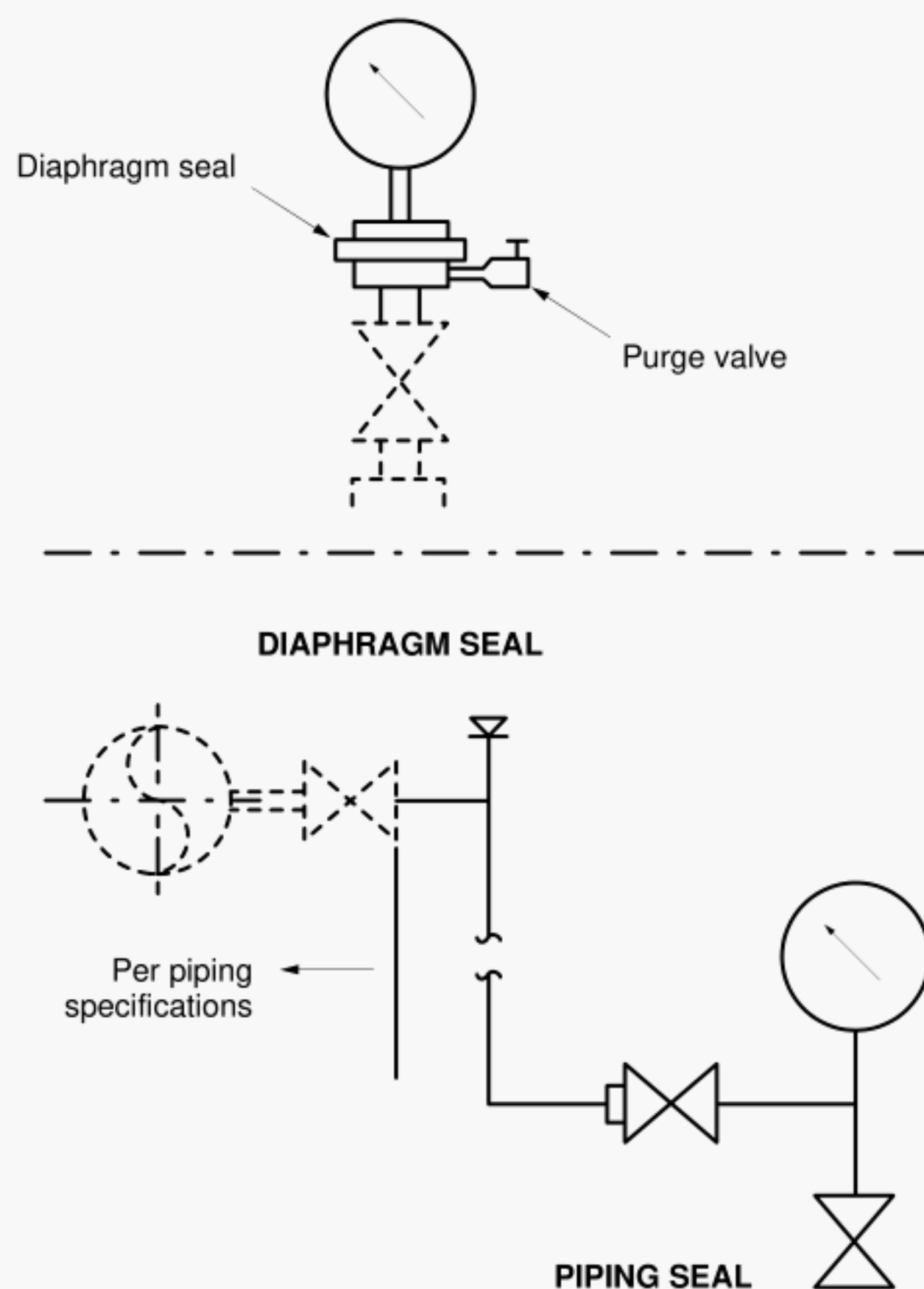


Figure 35—Seals for Pressure Gauges

be as long as 35 feet (10 meters). To avoid measurement errors, it is necessary to select capillaries of equal length and maintain them at the same temperature. To maintain good response and minimize temperature gradients on the capillaries, the capillary length should be as short as possible.

A similar style, which uses one seal, is used to measure pressure or the differential pressure between two streams when only one stream requires a seal. Measurement of differential pressure between combustion fuel oil and atomizing steam is an example of this application.

The level in atmospheric tanks can be measured with a seal assembly attached directly to the transmitter body. When no condensable materials are contained in the vapor space above the liquid, it is possible to connect a reference line to the low-pressure side of the transmitter and use it for measurement in a vessel under pressure.

Other styles are available for direct connection to specialized metering devices with chemical tees. Diaphragms can also be provided with extensions to reduce the volume of process-fluid pockets.

Whenever it has been determined that a diaphragm seal is required, the user should work closely with the supplier to ensure that the instrument configuration is appropriate for the application. Care should be taken to ensure that the seal

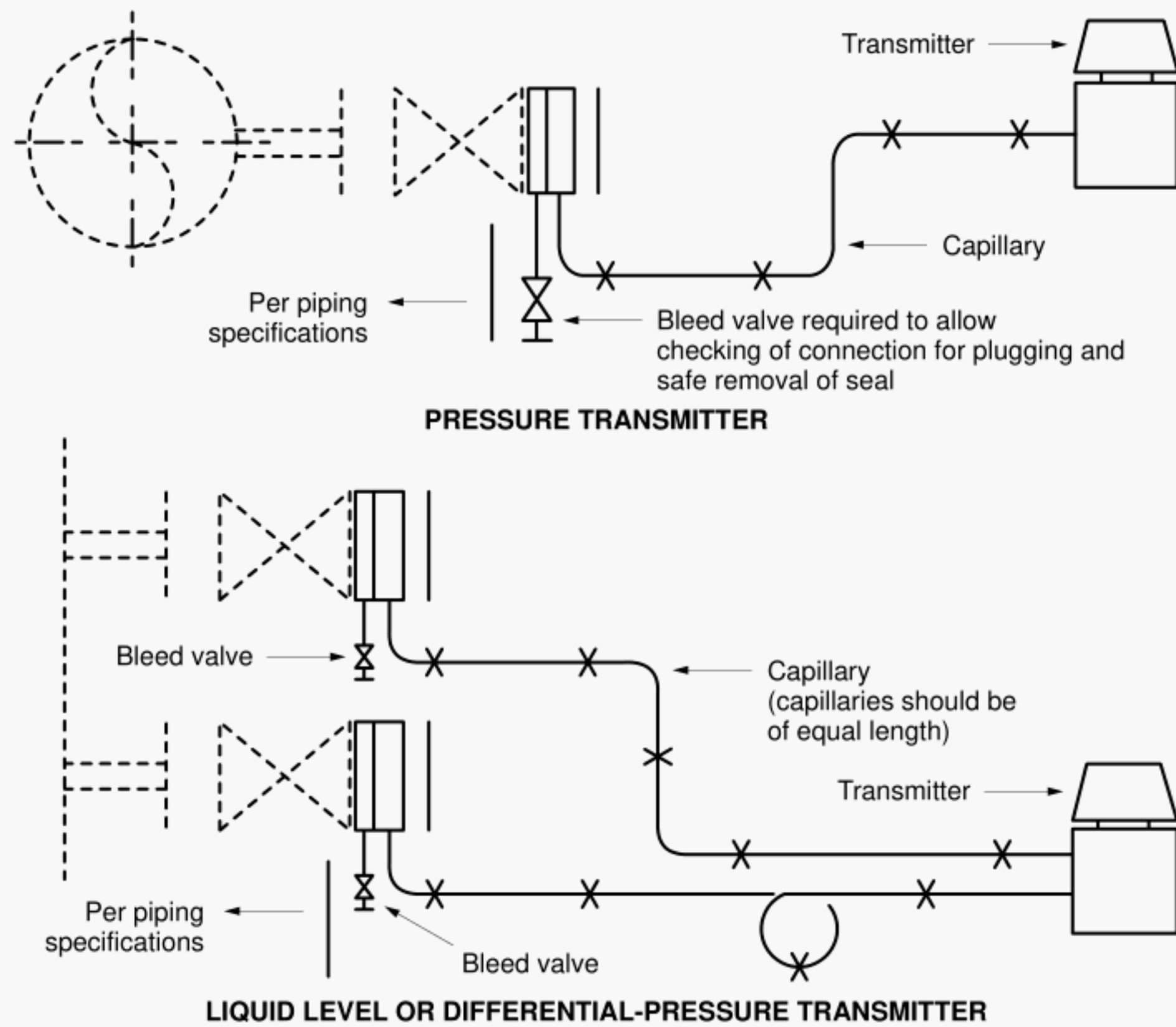


Figure 36—Diaphragm and Capillary System

fluid will operate over the required temperature range and be compatible with the process.

6.3.2 LIQUID SEALS

In many standard transmitter installations, the seal is the process fluid (see Figures 35 and 37). Most liquid flowmeters, steam meters, and condensable-vapor meters are sealed in this manner. The liquid cools, and the transmitter is not subjected to the process temperature. In many locations where steam is used, the condensed water must be protected from freezing. Whenever possible, the process fluid is the most desirable seal liquid, since a fresh supply is readily available in the event that the seal is lost through leakage or misoperation.

If a process stream contains hydrocarbons and water, it is likely that the fluid in the impulse lines will separate into two phases. If the transmitter is a flowmeter, different amounts of water could accumulate in the two sections of the piping, which could result in measurement errors. To prevent this, the piping should be filled with water or an ethylene-glycol-water mix, or else water-dropout pots (see Figure 37) should be used. In many locations, the use of glycol-water can eliminate the need for heating. Figure 38 shows a plot of the true freezing temperature of ethylene-glycol-water mixtures.

The seal fluid must be compatible with the process stream. The selected fluid must have a density higher than that of the process stream. It should be noncorrosive and have a low vapor pressure at the process temperature. Whenever non-process seal fluids are used, permanent warning tags or a special paint color should be used to indicate that a special seal fluid is enclosed.

6.4 Purges

6.4.1 GENERAL

Although purges are difficult to maintain, some process measurements are made possible only by the use of purging. Purge fluids are introduced into the instrument impulse lines, manifold valves, or the instrument itself and flow out through the process connections. The purge fluid serves to seal the instrument and sweep the lines clean of the process material. The purge fluid must be compatible with the process stream. Purge systems are commonly used on solids-bearing streams, streams subject to coking or solidification, and streams carrying corrosives or other contaminants that might damage the instrument or its connections. For solids-bearing streams, the purge instrument connections to the process should be vertically up or angled up. Figure 39 shows typical purging arrangements. The addition of purge

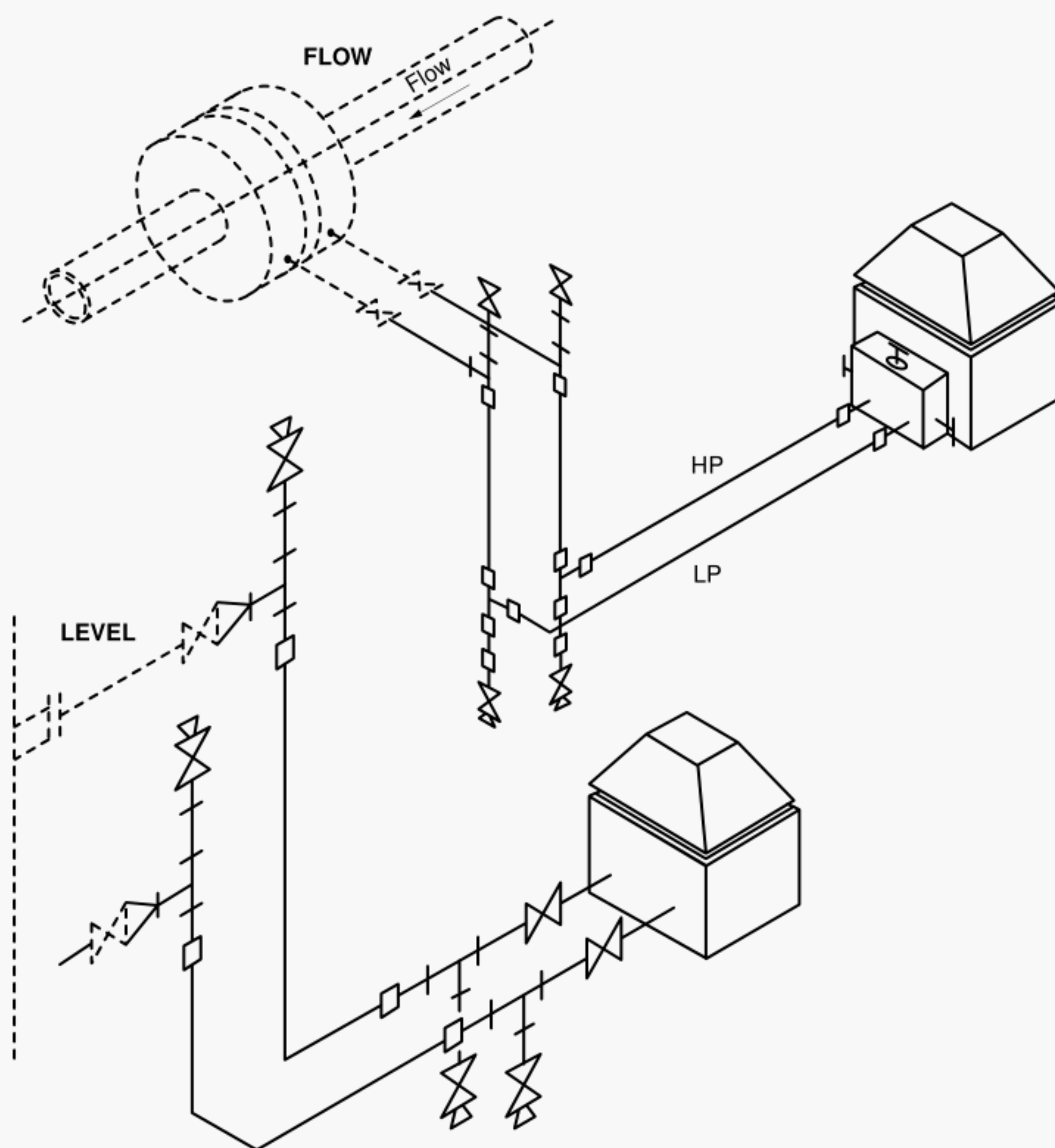


Figure 37—Liquid Seal Installations

fluid close to the measurement connection minimizes pressure drop due to the flow rate of the purging fluid. In some instances it is advisable to inject the purge fluid at the instrument, but this type of installation requires particular care in the design of the impulse piping and establishment of the purge flow rate to avoid measurement error.

Purge systems do not always eliminate the need for heating. Certain viscous streams require heat tracing not only for the instrument and its connections but also for the line supplying the purge fluid.

6.4.2 PURGE FLUIDS

Purging of instrument lines requires a suitable purge fluid (liquid or gas) at a pressure higher than the maximum process pressure possible at the point of measurement. This ensures continuous flow into the process connection. The purge fluid should be clean, free from solids, and compatible with and noncontaminating to the process. The temperature

of the purge fluid should not cause a change of state (flashing, condensation, or solidification) of the process or purge fluid.

The reliability of the source of supply is an important consideration. A source independent of the process is preferable so that it is available even when the process is not operating normally.

6.4.3 RATE OF FLOW

To be effective the purge fluid must be fed to the system continuously at a controlled rate. Restriction orifices, purge meters, or at high pressure, plunger pumps are used to determine and limit flow. Where the pressure at the point of measurement varies appreciably, a differential-pressure regulator should be used in conjunction with a restriction orifice or a purge meter to ensure a constant purge.

Too many factors are involved to attempt to set high flow limits. If errors exist as a result of excessive purge flow rate,

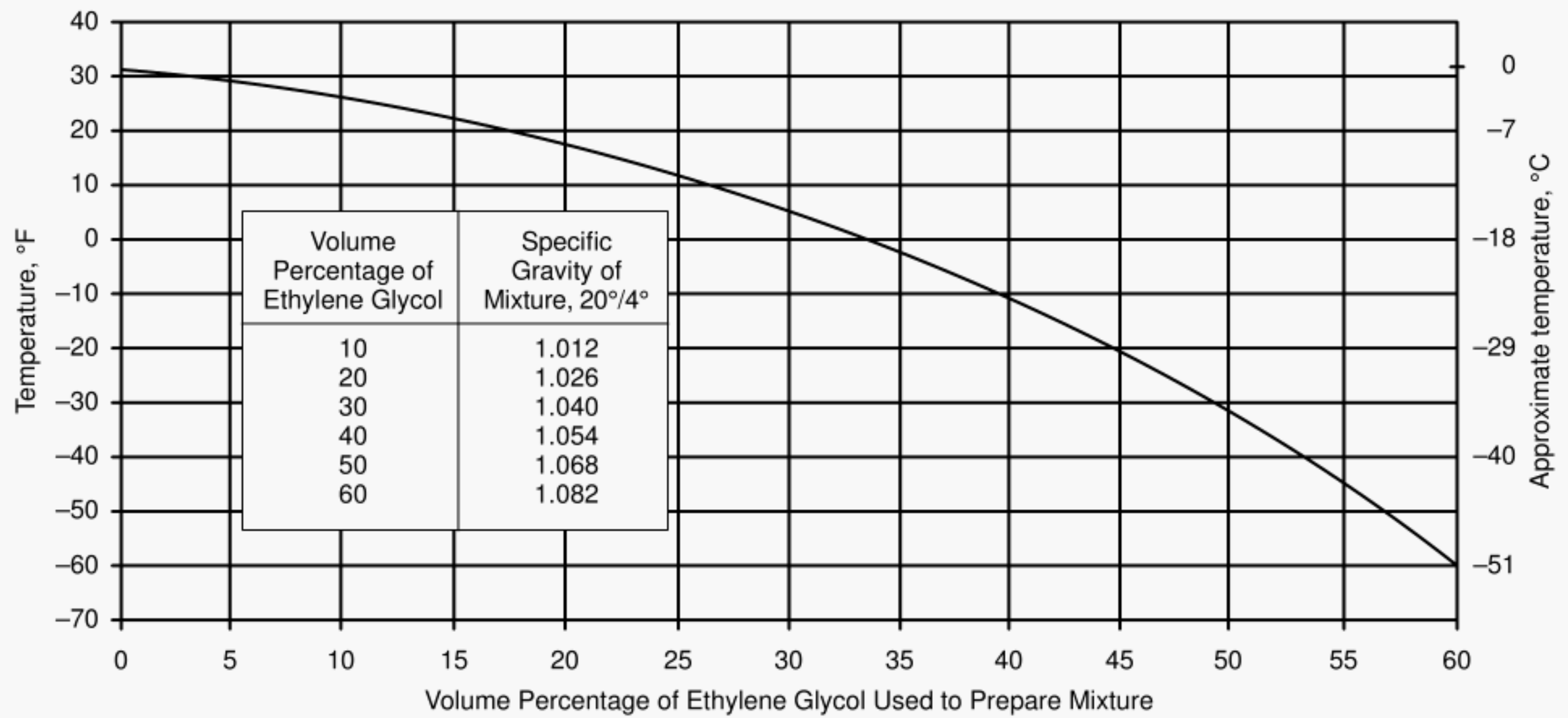


Figure 38—Freezing Points of Ethylene-Glycol-Water Mixtures

errors can be detected by momentarily stopping the purge flow and observing the transmitter output. Care should be exercised in calculating purge rates to orifice flanges because the orifice tap is bottom drilled to a depth of $\frac{1}{4}$, $\frac{3}{8}$, or $\frac{1}{2}$ inch

(6, 9.5, or 12 millimeters). The $\frac{1}{4}$ -inch (6-millimeter) orifice drilling may prove restrictive for the higher purge rate.

For gases, typical purge velocities range from 5 to 50 inches per second (2 to 20 centimeters per second). For liq-

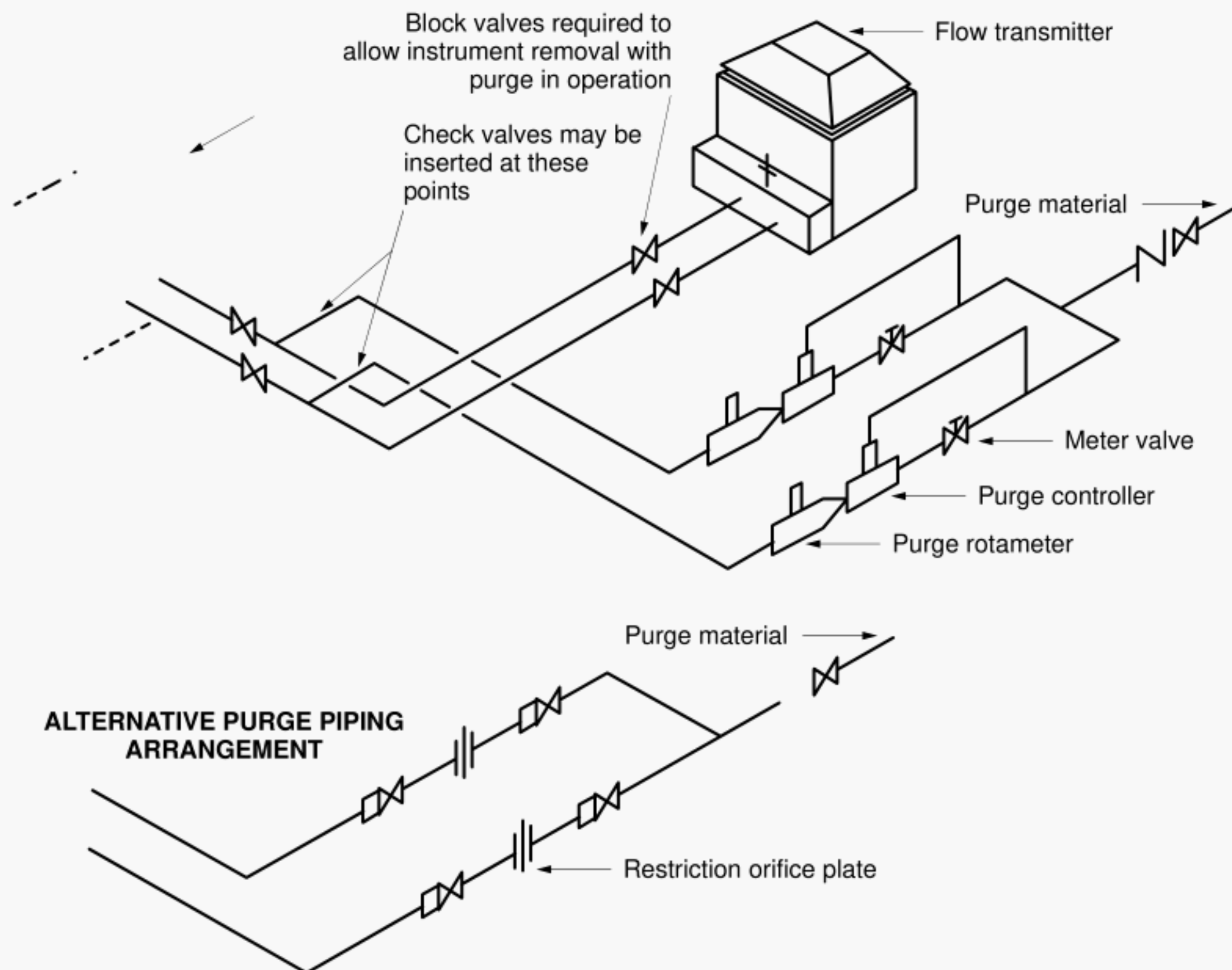


Figure 39—Purge Installations

uids, typical purge velocities range from 0.1 to 4 inches per second (0.4 to 1.6 centimeters per second). Figure 40 shows recommended purge rates for various tap drilling sizes. The flow rate to each tap on an orifice meter installation should be the same.

The purge rotameter is the most convenient device for determining and establishing purge flow.

Note : Glass-tube rotameters should not be used for hydrocarbons or hazardous chemicals.

A standard purge rotameter with a range of 0.38–3.8 gallons per hour (1.4–14.0 liters per hour) of water or 0.2–2.0 actual cubic feet per hour (6.0–60.0 liters per hour) of air is normally satisfactory for purging clean fluids; however, where the process fluids tend to clog or deposit sediment, the rate should be increased.

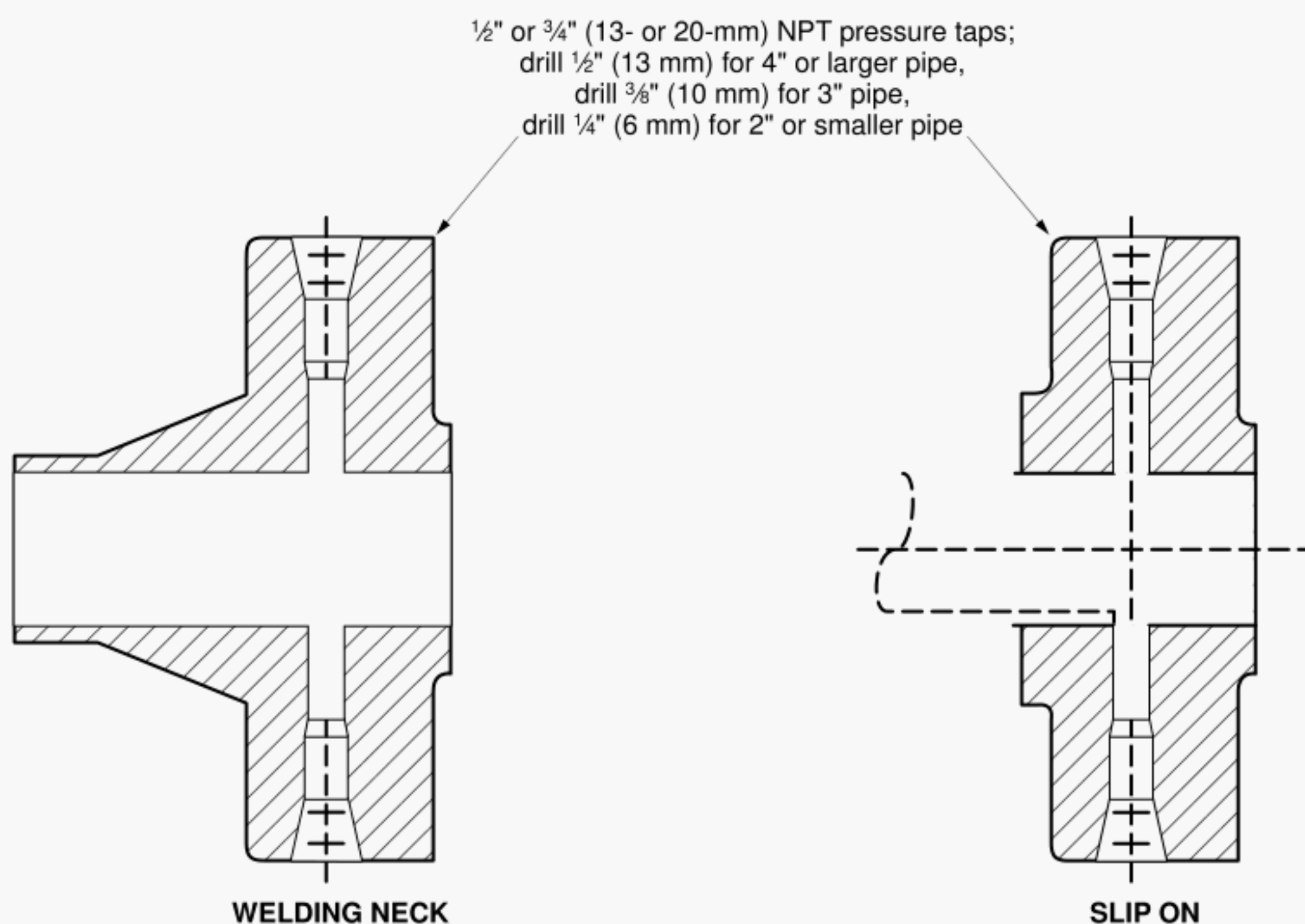
Properly sized and installed restriction orifices provide reliable service when the pressure across them is properly regulated. The flow rate of liquids or gases through such orifices can be calculated by formulas found in flow metering, mechanical engineering, and similar handbooks. The calculated

orifice sizes are normally rounded to the nearest standard drill size.

6.5 Heating

6.5.1 GENERAL

The need for housings, heating and insulating instruments, and impulse lines will depend on the severity of the winters in the locality. In existing plants, past experience normally determines the extent of protection required. Where experience is not available, official weather-service data should be used. To ensure that the instruments remain operable under the most severe conditions, the design should be based on the lowest temperature and highest wind velocity for the coldest month of the year. Where applicable, the use of either steam or electrically heat-traced tubing bundles can simplify installation and reduce future maintenance problems. Manufacturers of heated and insulated enclosures test their products at various temperature and wind-velocity conditions and should supply performance data that are helpful in system design.



Orifice Flange Drilling		Gas Flow		Liquid Flow	
Inches	Millimeters	Cubic Feet per Hour	Cubic Meters per Hour	Gallons per Hour	Cubic Meters per Hour
1/4	6.0	1.0	0.03	3.0	0.01
3/8	9.5	2.0	0.06	5.0	0.02
1/2	12.0	5.0	0.15	8.0	0.03

Figure 40—Orifice Tap Purges for Flowmeters

Instrument and impulse lines that contain dry, nonviscous, nonfreezing fluids with pour points below the minimum temperatures encountered require no heating or winterizing protection, but such materials are rarely found in refinery processing units. Most refineries, particularly those that must design for subfreezing temperatures, consider many process fluid streams to be water bearing and all process gas streams to be water saturated, so systems are designed accordingly.

In designing a heating system, it is usually necessary to consider instruments in the following four general categories:

- a. Instruments for measuring and controlling process streams that have pour points below 32°F (0°C), such as gases, light hydrocarbons, and intermediate distillates. Although some of these streams, when wet, form hydrates that solidify above 32°F (0°C), it is usually sufficient merely to warm such systems to prevent the formation of ice. Therefore, such installations are designated *warming services*.
- b. Instruments for measuring and controlling streams with elevated pour points, such as pitch, heavy residuals, and process chemicals such as phenol that solidify above 32°F (0°C). In such systems it is necessary to keep the temperature of the process fluid above its pour point to ensure free flow. Such installations are designated *high-pour-point services*.
- c. Special instrumentation and piping systems, which often require additional protection for operation and maintenance tailored to the service involved. Process stream analyzers and their sampling systems are an example.
- d. Instruments with specific temperature limitations, both maximum and minimum, imposed by the manufacturer to ensure accurate and reliable operation.

Although no well-defined limits have been determined for the categories above, each has requirements and limitations that must be considered, regardless of the heating method used. The most common heating methods are steam heating and electrical heating, and each has specific characteristics that are advantageous if used properly.

6.5.2 STEAM HEATING

6.5.2.1 General

Since steam is normally available in refinery process units, steam heating has the advantage of being readily accessible. Steam supplies high-density heat from condensation, and large quantities of heat can be obtained from a single tracer line. On the other hand, steam delivers heat at a temperature that corresponds to the saturated steam pressure in the tracer, a minimum of 212°F (100°C), which may overheat some instruments or impulse lines unless care is exercised.

For most installations, a steam-tracing and heating system should be provided that is independent of process operation, equipment maintenance, and unit shutdown. In subfreezing

climates, it may be necessary to take this supply from the main steam header and to provide a pressure-reducing station that can be adjusted to meet winter and summer ambient conditions. Steam pressure can be adjusted to minimize overheating when the “heavy-tracing/light-tracing” concept shown in Figure 41 is used during initial installation.

The use of automatic regulators that sense ambient temperature and regulate steam pressure in tracing lines should be considered. These valves can minimize problems associated with overheating and freezing of lines.

6.5.2.2 Steam Tracing for Warming Services

6.5.2.2.1 General

Warming services require steam tracing to prevent the formation of ice and hydrates and undesirable gas condensation. The problem, however, is to avoid overheating, which can cause boiling in the instrument and lines or which can cause damage. Danger from overheating can be minimized by “light tracing,” in which direct contact between the hot tracer and the line or instrument is prevented by the use of insulation or spacing (see Figure 41).

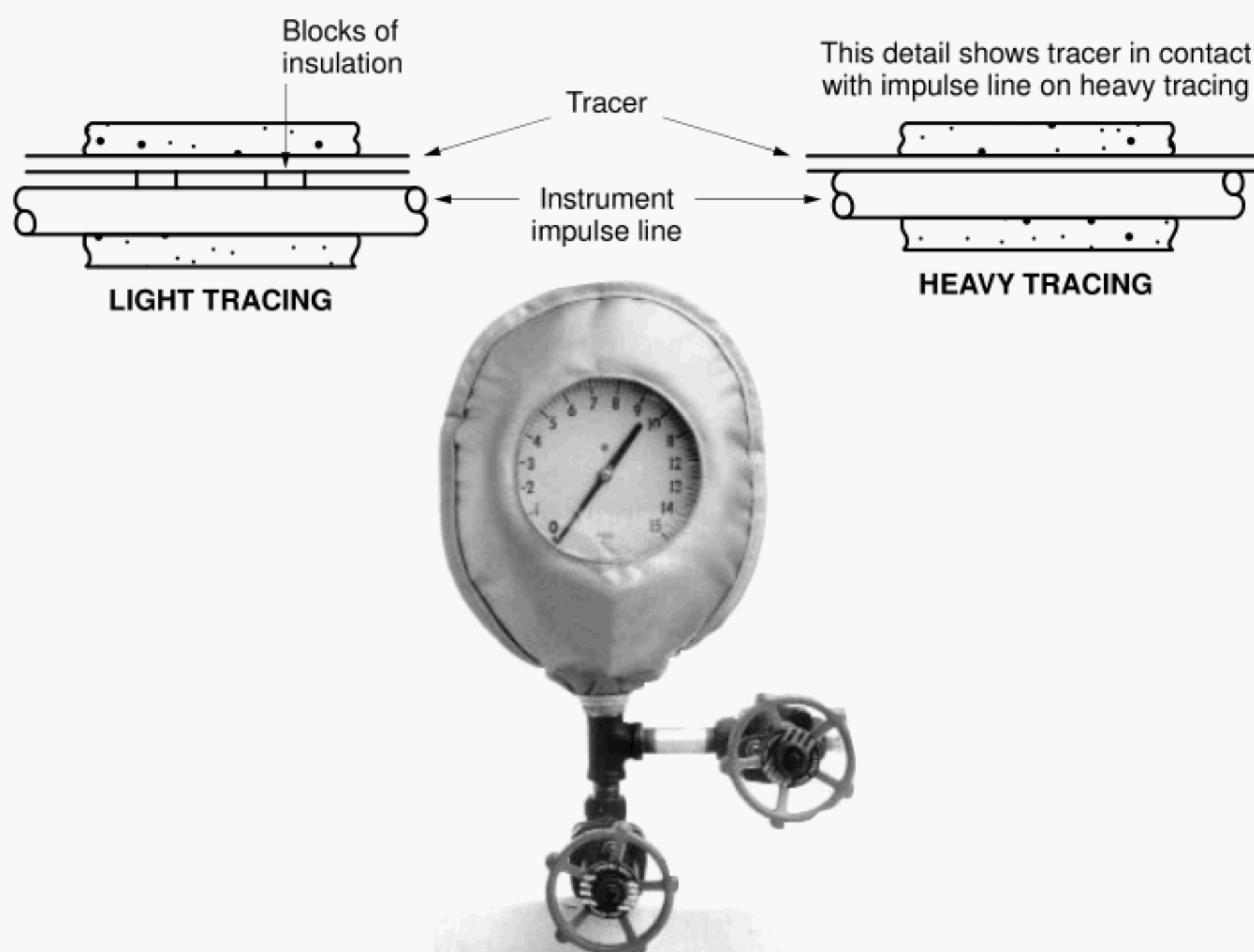
6.5.2.2.2 Instrument Housings

Where weatherproof transmitters for pressure and flow instruments can be close coupled to the point of measurement, heating can be simplified by using a molded insulating-plastic enclosure that fits snugly around the instrument and is strapped in place to prevent moisture from entering. This unit protects and insulates the instrument and allows the use of several techniques for heating. Another method of providing heat within the enclosure is to use a radiant heater. This method simplifies servicing because the heater is not connected to the instrument.

Insulated plastic enclosures are available for all types of transmitters, and special types are available that enclose connection valves and manifolds of specific configuration. These enclosures (see Figure 42) can be used for transmitters that cannot be close coupled, for example, pressure and flow transmitters for which the point of measurement is not accessible.

Where weatherproof instruments are not used or where the instruments require frequent servicing or access, use of a heated and insulated housing is required. Various types of housings and their mountings are shown in detail in Figure 43. Housings should be rainproof, dustproof, and corrosion resistant.

Housings should provide sufficient working space for routine maintenance and should have access doors sized and located for easy removal of the instrument or instruments. Lines should enter through the bottom or sides of the housing, and the entry to the housing should be adequately sealed. Observation windows are available. Insulation and heating coils may be factory or field installed.



TYPICAL PRESSURE GAUGE INSTALLATION

Note: Insulation must not be applied in a manner that obstructs the gauge's blowout-protection features.

Figure 41—Steam Tracing and Insulation for Instrument Lines and Pressure Gauges

6.5.2.2.3 Tracing Methods and Materials

The arrangement shown in Figure 42 is normally used with the heavy-tracing/light-tracing methods shown in Figure 41, with minor variations required for specific cases. The supply header should be above the equipment to be traced. Each branch, which should serve only one instrument, or each widely separated lead line should come off the top of the header and be supplied with a shutoff valve. Ideally, tracing should slope downward continuously to prevent pockets and facilitate drainage. Where pockets cannot be avoided, the diagram and equation in Figure 42 should be consulted for guidance.

A separate trap and condensate isolating valve should be provided for each tracer. Where steam tracing is extensive, a tracing piping plan should be provided to show the location of steam shutoff valves and associated instruments, traps, and condensate isolating valves. The steam and condensate shutoff valves nearest the instrument should be permanently tagged with the associated instrument designation. Temperature-sensitive traps that are specifically designed for heating and warming services are available. These often serve as a combination trap and control thermostat. The isolation valves, traps, and thermostats should be installed to allow for ease of checking and maintenance. Installation procedures

and maintenance requirements are usually defined by the supplier.

Copper or stainless steel tubing sized for the particular service should be used to carry the heating steam. Aluminum tubing should not be used because it is subject to corrosion, particularly by magnesia insulation. Carbon steel tubing rusts not only externally but internally when heating is seasonal or intermittent. The internal rust clogs or damages traps.

Joints in tracing tubing should be avoided if possible. When joints are necessary, they should be made outside the insulation with expansion loops to prevent stress on the fittings. Only high-quality fittings should be used. To protect personnel, the loops should be separately insulated. Examples of methods of tracing different types of instruments are shown in Figures 44–46.

6.5.2.2.4 Insulation and Protective Covering

The entire tracing system for impulse lines should be carefully insulated and waterproofed. Particular care should be used at the point of measurement and at the entry into the insulated enclosure. A durable protective cover should be used. Where stainless steel tubing is used, chloride-free insulation must be specified to prevent stress corrosion cracking.

The system should be designed and installed to minimize damage to the insulation during routine service or maintenance. Commercially available insulating enclosures designed to allow for routine maintenance can be used.

6.5.2.3 Steam Tracing for High-Pour-Point Materials

6.5.2.3.1 General

The difference between warming service and high-pour-point service is the temperature required to keep the material fluid in the instrument and impulse lines. When low-pressure [less than 50 pounds per square inch absolute (350 kilopascals)] steam heat is used for high-pour-point service, heavy

tracing is required, as shown in Figure 41. More heat transfer can be achieved by using heat transfer cement or more than one tracer. As a general precaution, care must be taken to ensure that the high-temperature limit of the instruments and the temperature/pressure rating of the tubing are not exceeded.

6.5.2.3.2 Instrument Housings

Housings for instruments in high-pour-point service are usually identical to those used for instruments in warming service, except that a larger coil is required and extra protection may be necessary to prevent maintenance personnel from being burned.

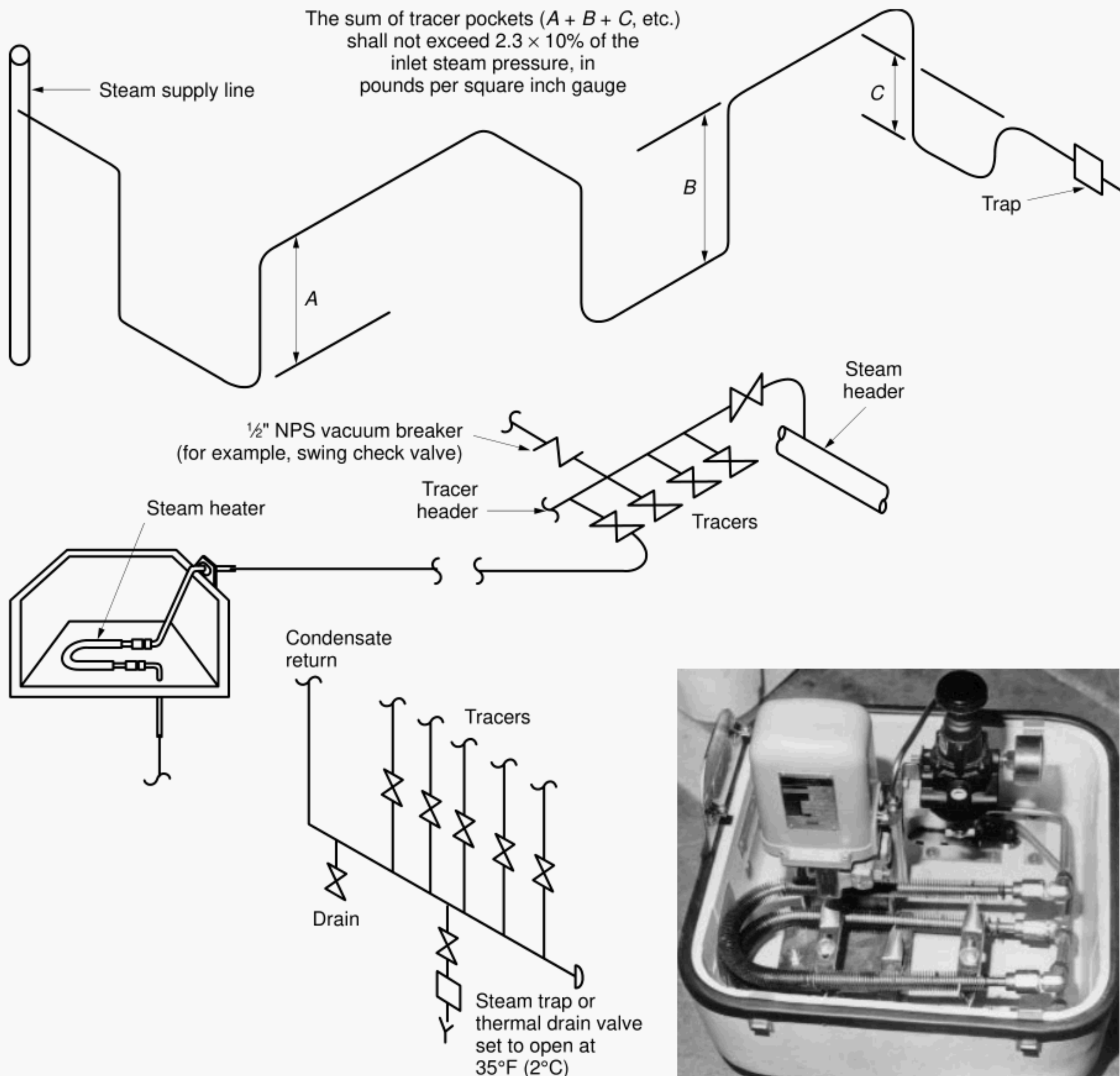


Figure 42—Steam Tracing and Heating



Figure 43—Instrument Housings

6.5.2.3.3 Tracing Methods and Materials

Tracing methods for high-pour-point service are similar to those used for warming service, except that heavy tracing should be used. Materials for tubing and fittings are identical to those used in warming service.

6.5.2.3.4 Insulation and Protective Covering

Insulation and protective covering for high-pour-point service are similar to those used for warming service, except that in some cases, heavier insulation may be required.

6.5.3 ELECTRICAL HEATING

6.5.3.1 General

Electrical heating is widely used. When heating elements are selected, care should be exercised to ensure that they are not potential sources of ignition. Several types of cable are available (for example, mineral insulated and self-limiting). Fittings, relays, and thermostats must be suitable for the area classification. Guidance in meeting these requirements is given in NFPA 70, Article 500. Local codes must also be followed.

Several considerations are involved in the design and installation of electrical heating to ensure that the heating system will operate properly during start-up and continued plant operation. The thermostat sensor must be located properly and set at the correct temperature. The thermostat should be installed so that its setting can be checked with the thermostat in place. A means of indicating that the cable is functioning properly is required.

Special care should be exercised during installation to follow the manufacturer's recommended practices concerning, for example, minimum bend radius and weather protection. The factors outlined in 6.5.3.2 and 6.5.3.3 should be considered in the design and installation of electrical heating.

6.5.3.2 Electrical Tracing for Warming Services

6.5.3.2.1 General

Electrical heating to prevent the formation of ice and hydrates and the condensation of undesirable vapor has proved to be economical and trouble free. If the thermostat is set properly and the line tracing is designed for the required heat delivery and heat distribution, overheating is seldom a problem.

Self-limiting cable has several advantages for warming service. No thermostats are required to operate the system (that is, maintenance costs are reduced), and the self-limiting cable eliminates the potential for hot spots. In some cases,

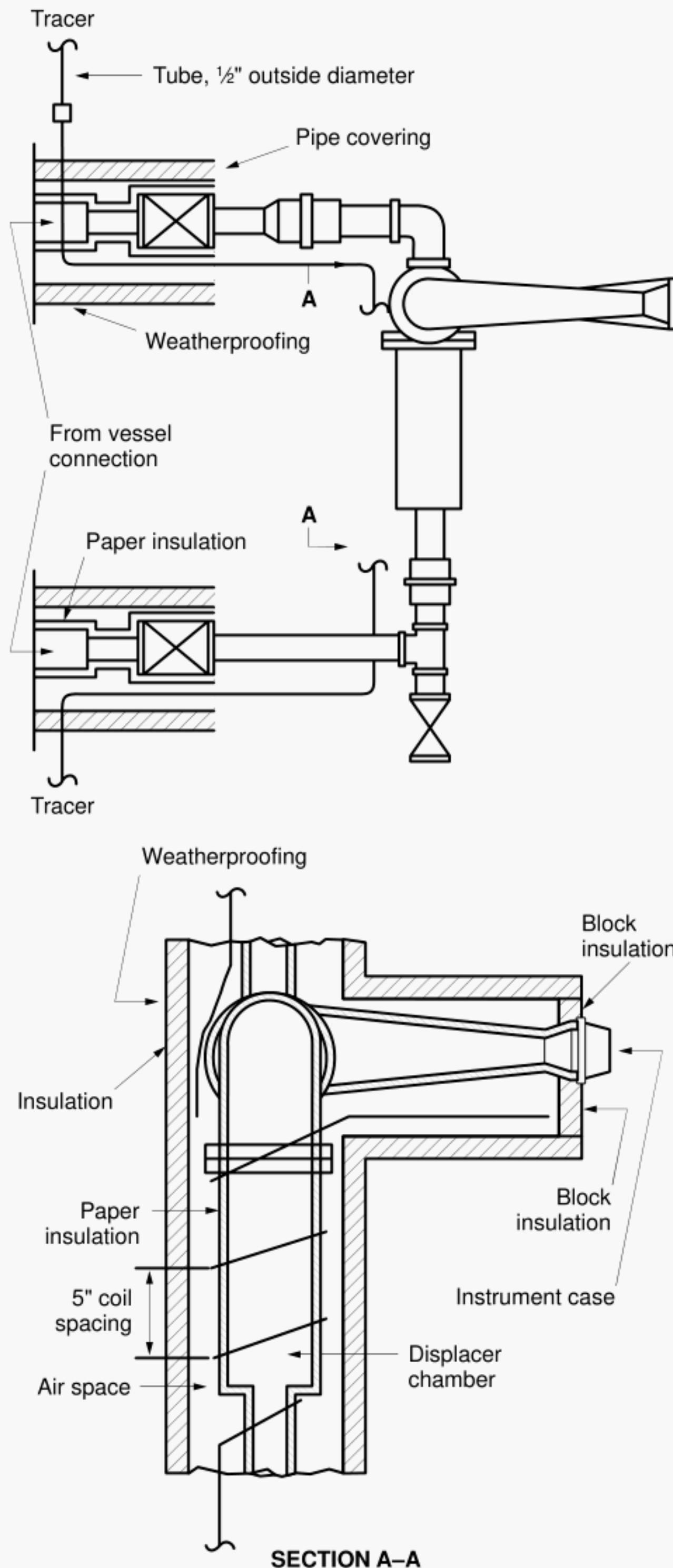


Figure 44—Steam Tracing and Insulation for External Displacement Level Instrument

the trace heating for the piping and the instrument can be combined to reduce cost.

6.5.3.2.2 Instrument Housings

Molded plastic enclosures are available with electric heaters. Most warming installations of this type are successful even in severe climates. A typical insulated box enclosure is shown in Figure 47. The enclosure manufacturer should be consulted to ensure that the design is adequate for the specific ambient temperature and wind velocity.

6.5.3.2.3 Tracing Methods and Material

The tracing methods shown in Figures 48 and 49 are adequate for most installations. The use of electrically traced bundled tubing (see Figure 50) may be advantageous.

6.5.3.2.4 Insulation and Protective Covering

Insulation and protective covering should be designed and installed for maximum weatherproofing and mechanical protection. The design should permit repair or removal of the instrument without damage to either insulation or sheathing.

6.5.3.3 Electrical Tracing for High-Pour-Point Materials

6.5.3.3.1 General

Electrically traced instruments in high-pour-point service require more heat and higher temperature than do instruments in warming service. The heat tracer must therefore be in continuous contact with the impulse lines for good heat transfer. Sheath materials for cable have maximum allowable surface temperatures. These temperatures must be checked to ensure that the sheath material used has a high enough rating.

If bundled tubing is used, the maximum allowable temperature of both the tracer and the bundle insulation must be checked. Instrument housings and tracing and insulation methods are similar to those used in warming service.

6.5.3.3.2 Instrument Housings

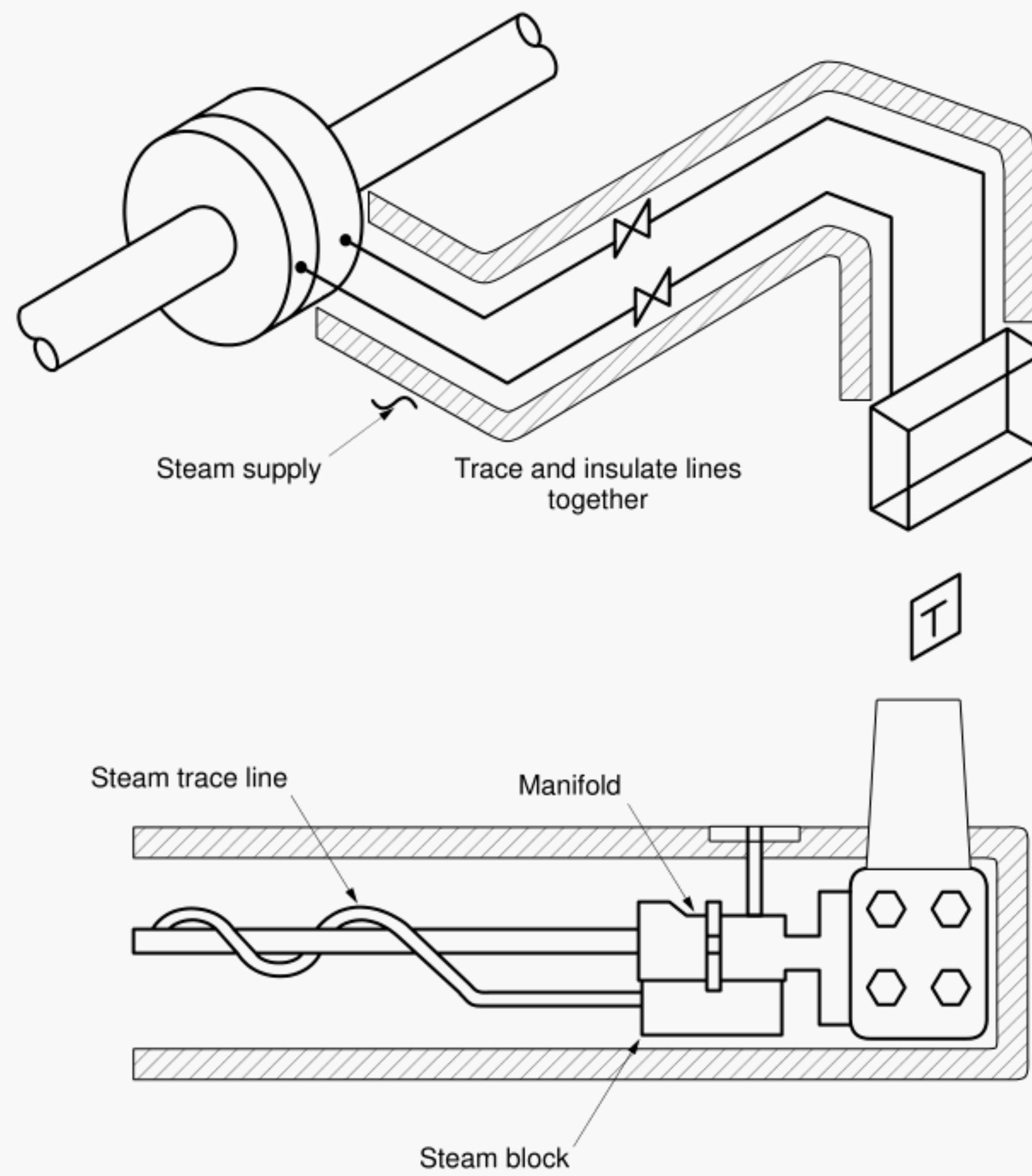
Instrument housings for high-pour-point service are similar to those described for warming service, with additional heat supplied where necessary.

6.5.3.3.3 Tracing Methods and Materials

Tracing methods and materials for high-pour-point service are the same as those described for warming service.

6.5.3.3.4 Insulation and Protective Covering

Because of the high-density heat used in high-pour-point service, insulation must be heavy and installed with particular care. Bare spots or poorly insulated areas that may cause localized solidification of stagnant material in the lines or instrument cannot be allowed.



Note: All tracers should have a shutoff valve at their source, as well as a steam trap or valve termination for condensate disposal.

Figure 45—Typical Steam Tracing for Flow Transmitter

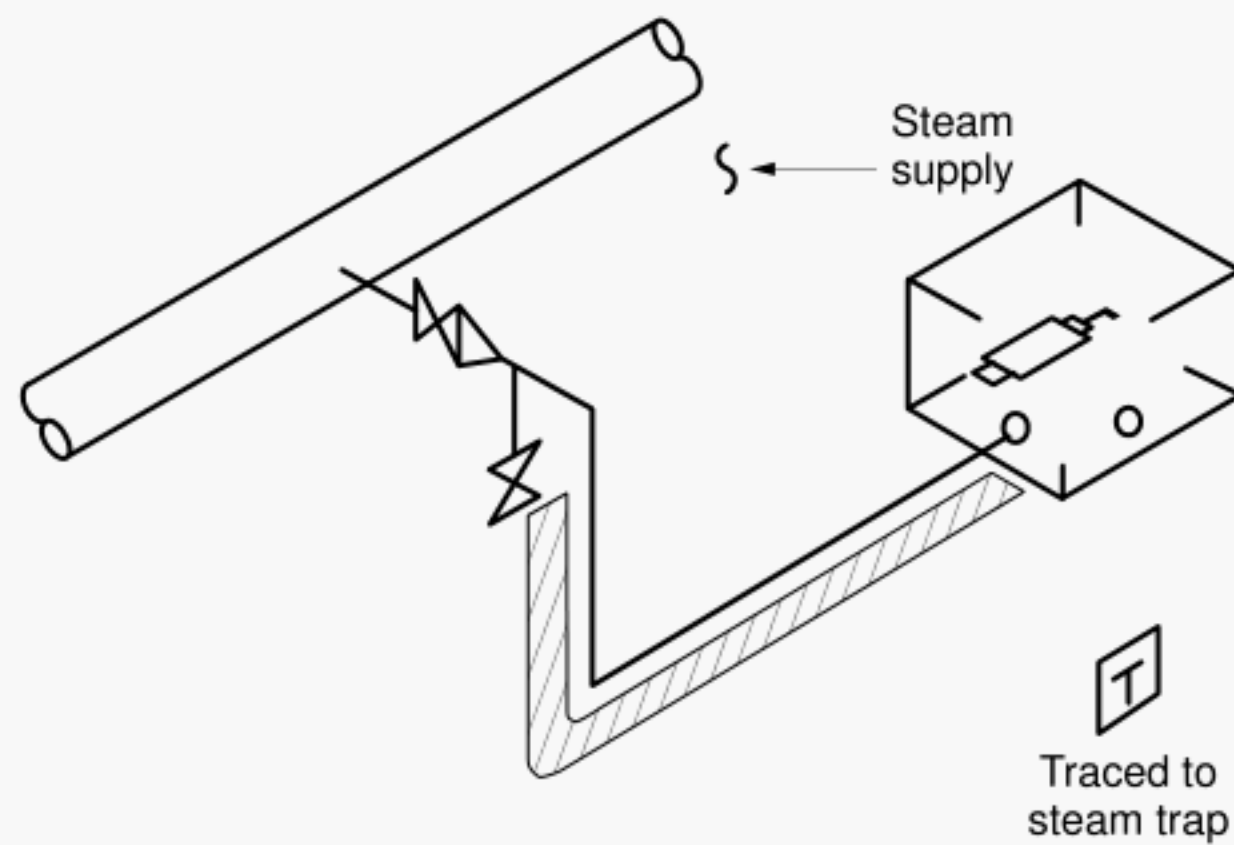


Figure 46—Typical Steam Tracing for Pressure Transmitter

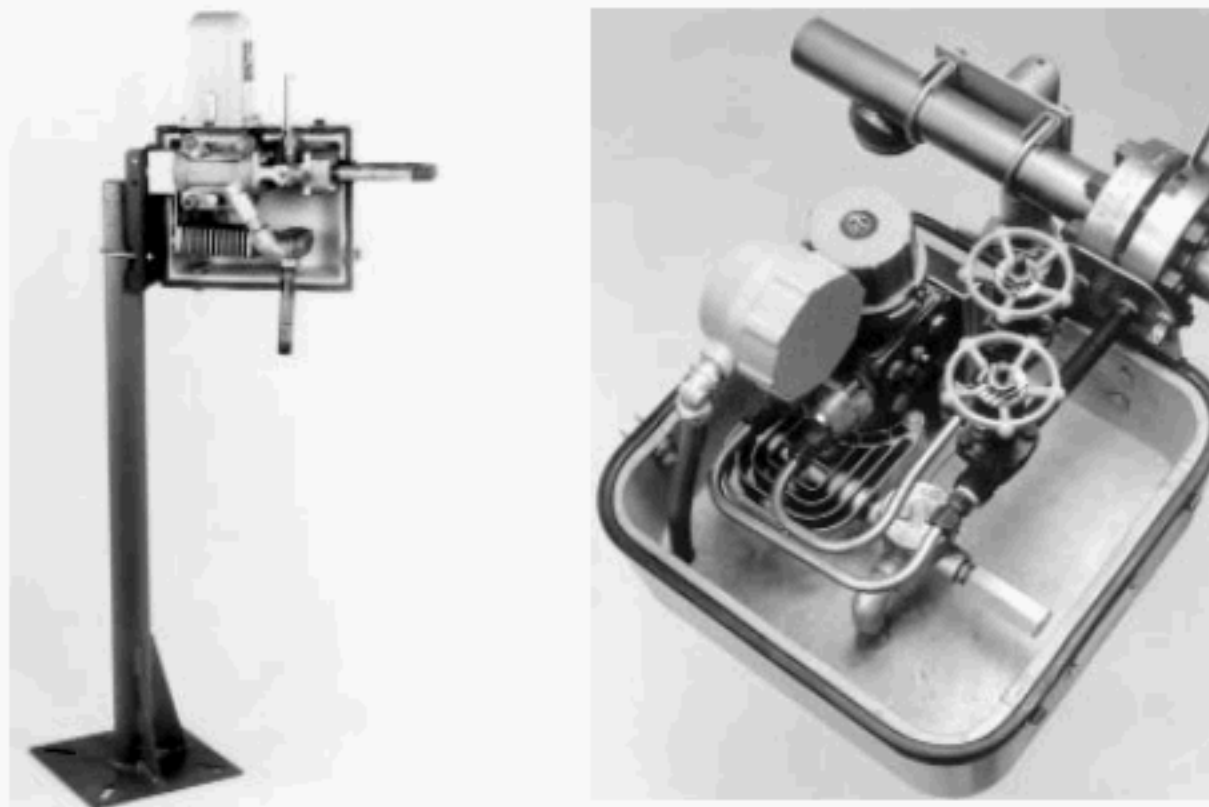
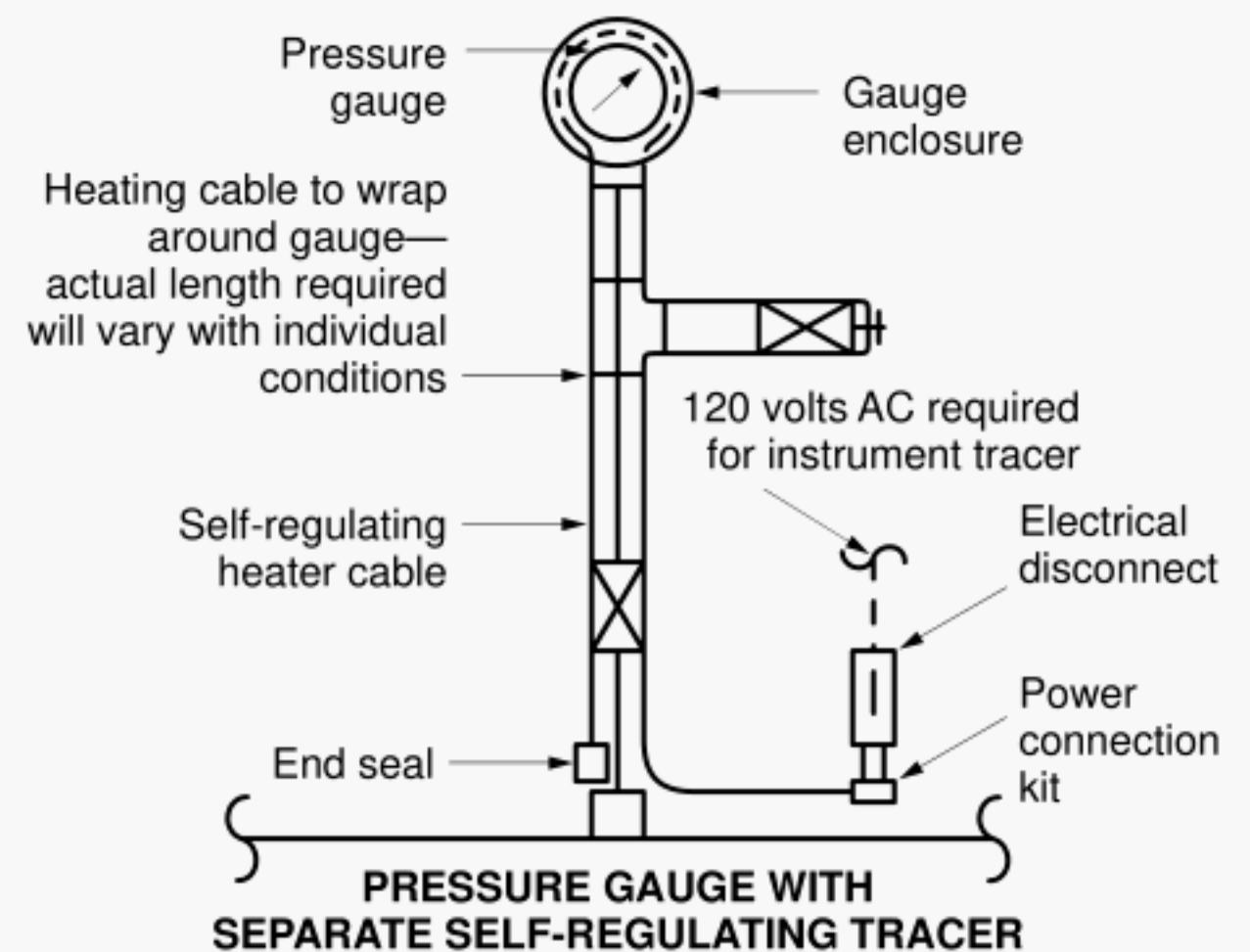
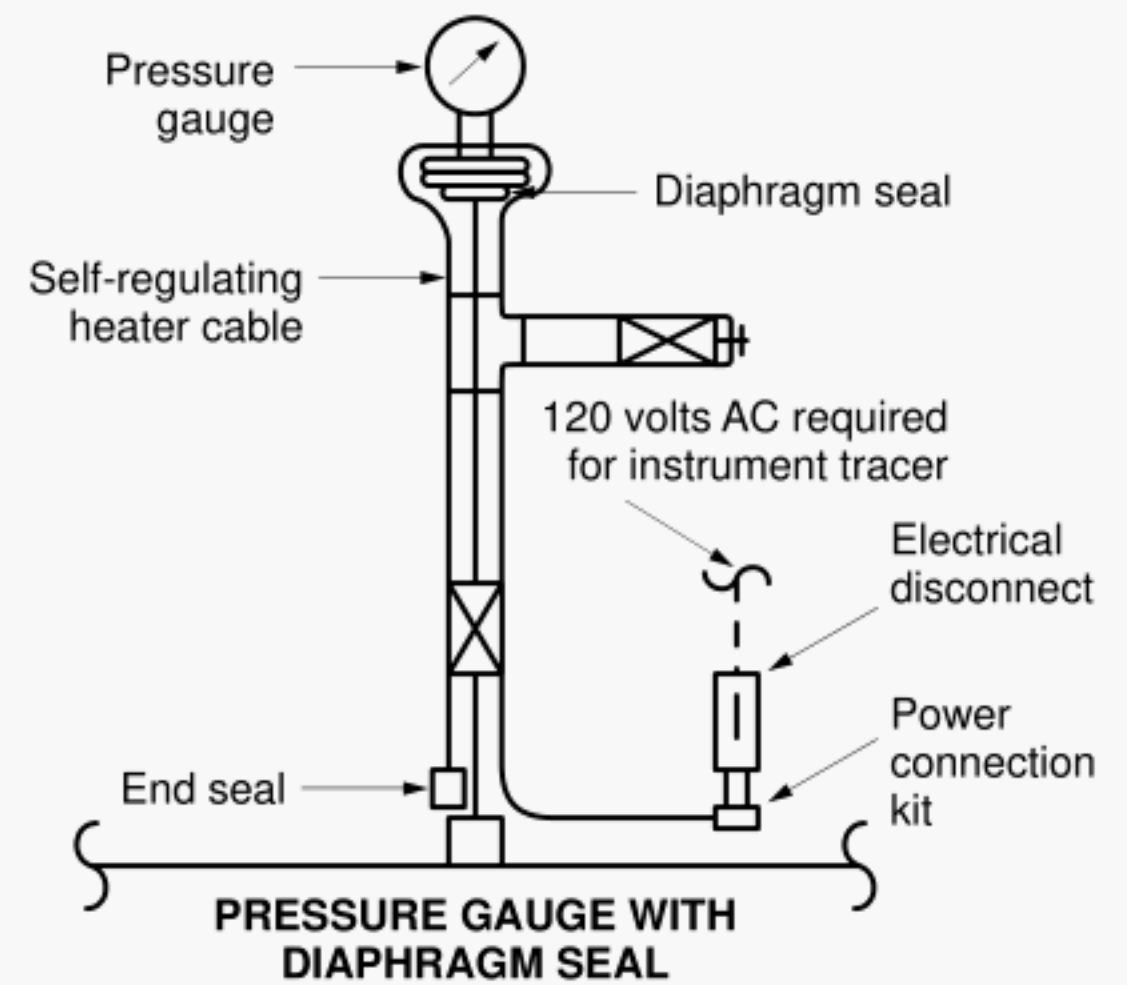
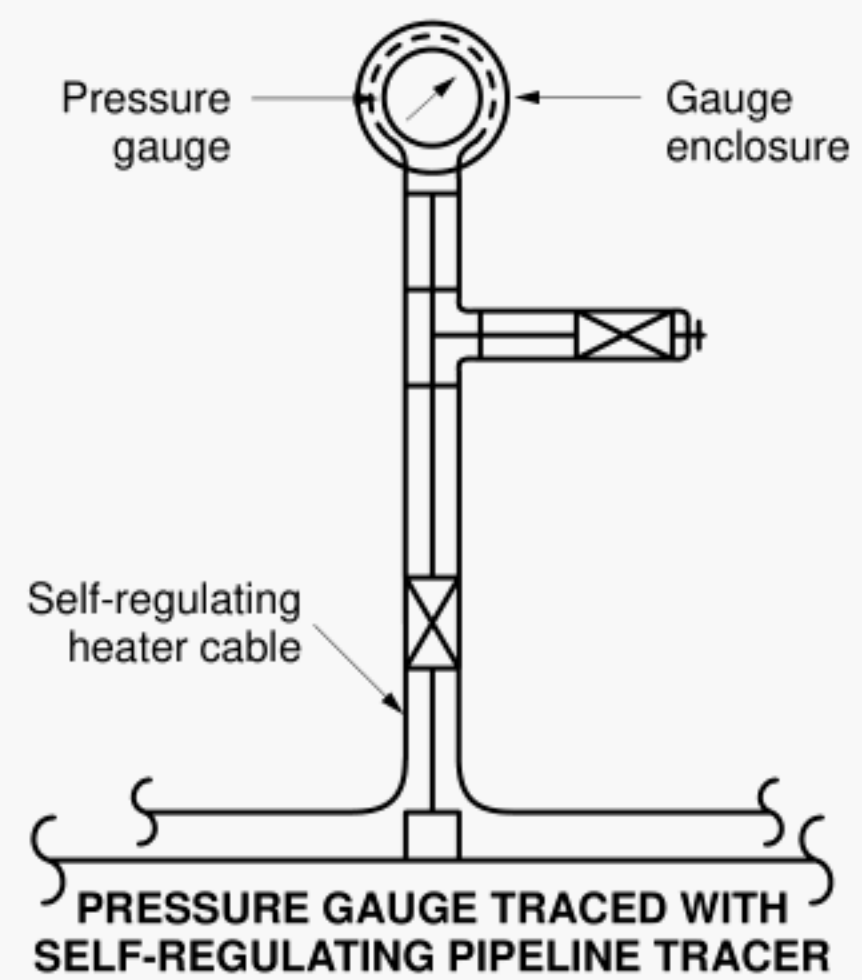


Figure 47—Typical Electrical Tracing and Instrument Enclosures



Note: To conserve heat, insulation should be installed from the enclosure to the process connection.

Figure 48—Electrical Tracing and Insulation for Pressure Gauges

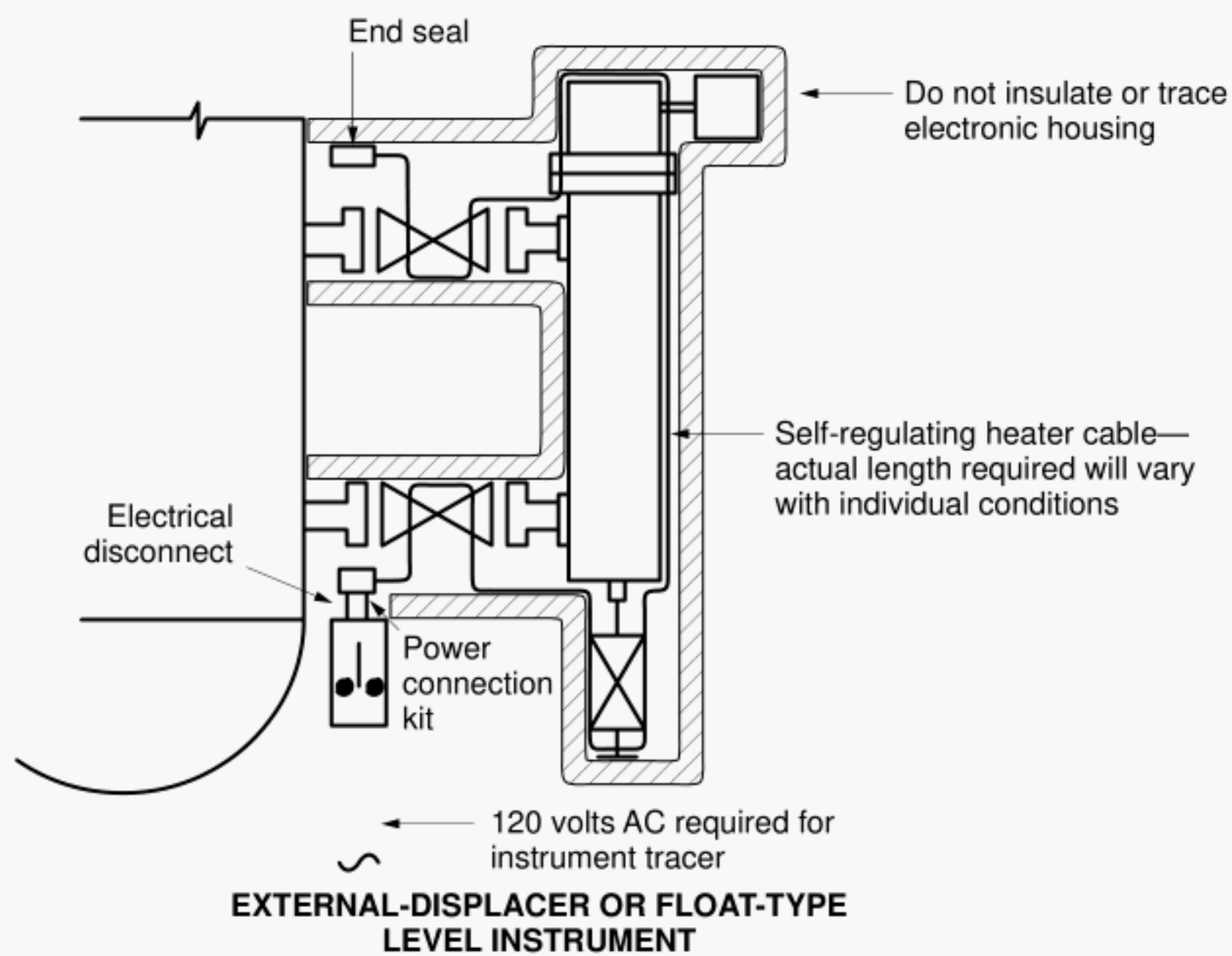
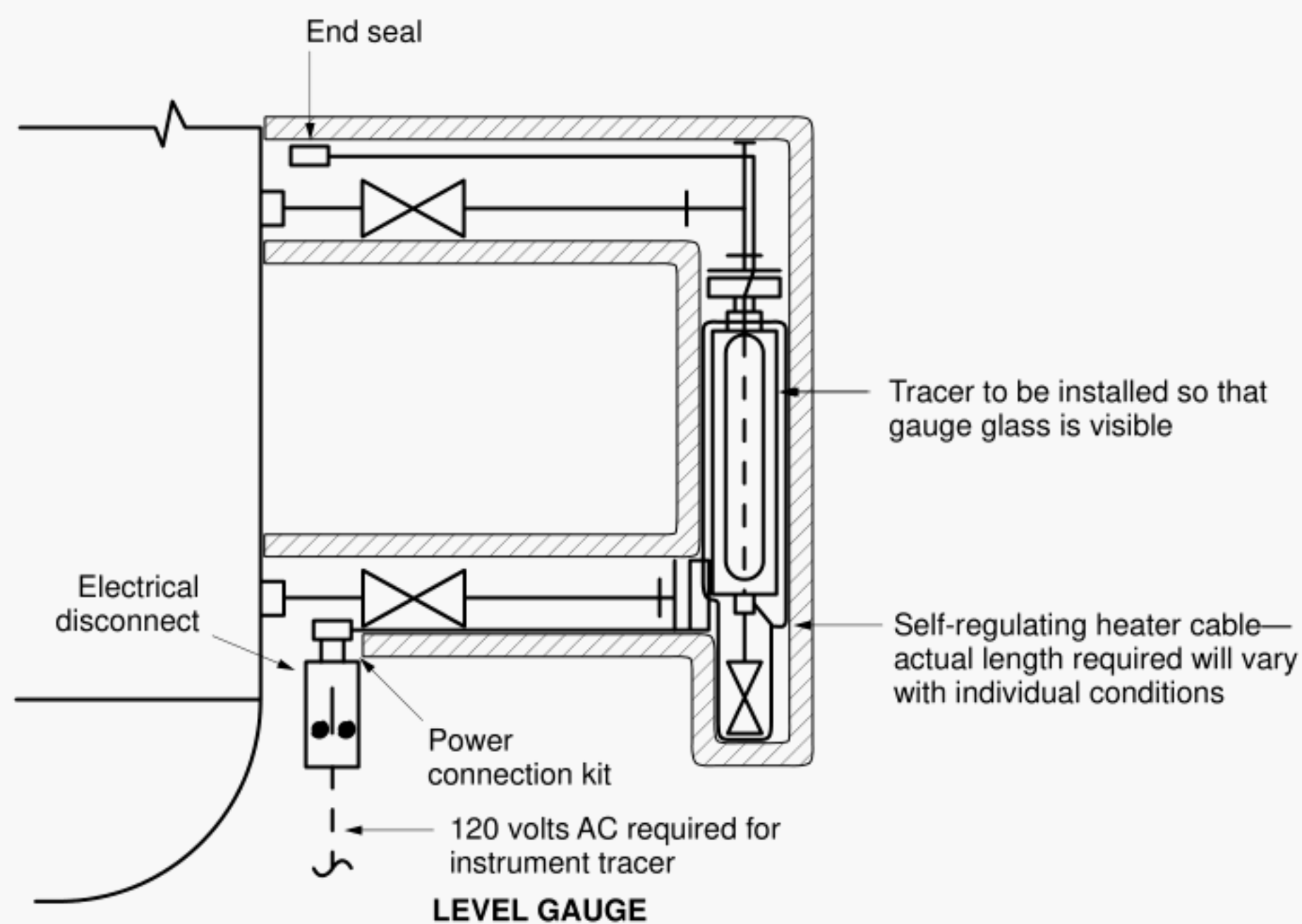
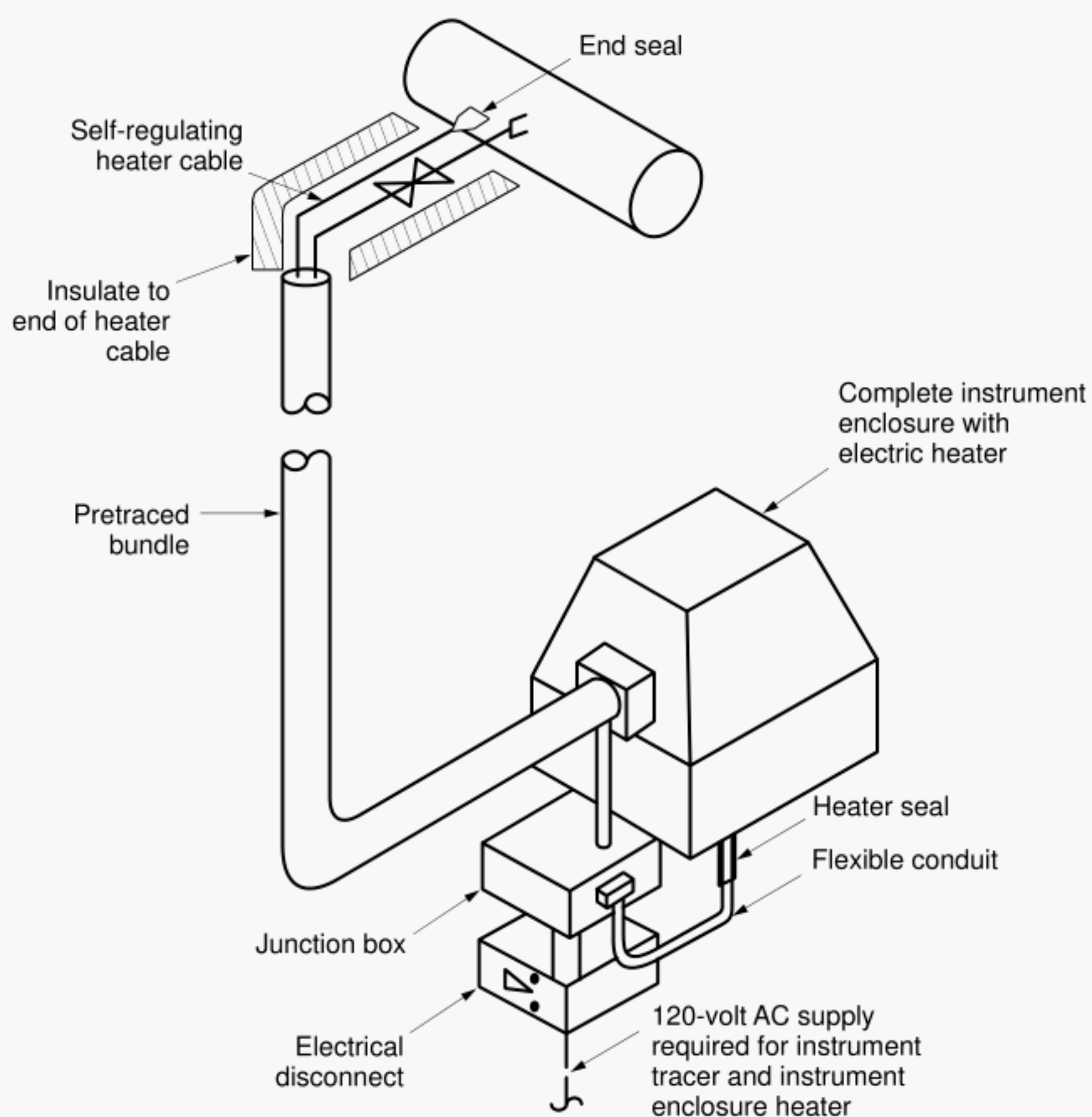


Figure 49—Electrical Tracing and Insulation for Level Instruments



Note: To conserve heat, insulation should be installed from the end of the bundle to the process connection.

Figure 50—Electrical Tracing and Insulation for Instruments

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