Sensors

Sensors are used for process monitoring and for process control. These are essential elements of safe and profitable plant operation that can be achieved only if the proper sensors are selected and installed in the correct locations. While sensors differ greatly in their physical principles, their selection can be guided by the analysis of a small set of issues, which are presented in this section. Each issue is introduced here with process examples, and details on the issues are provided in the remainder of this site for the most common sensors in the process industries.

Exercise 2.01 You have just started your first job as an engineer. You supervisor presents you with the process drawing in Figure 2.01. She asks you to provide sensors for this process. "Please have your proposal ready tomorrow for the design review meeting."

You have two challenges.
1. What variables should be measured?
2.What sensor should be specified for each measurement?

For guidance on selecting the process variables, see Chapter 2 and Chapter 24 in Marlin (2000). Guidance on selecting sensors is provided in this site, with an introduction to the key issues in this section.

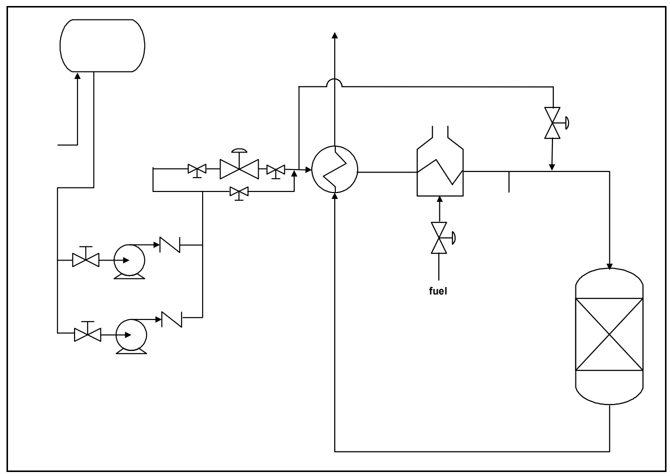


Figure 2.01 Reactor with feed-effluent heat exchanger.

When defining sensor requirements and principles, the engineer should use terminology that has a unique meaning, which is not easily achieved. Therefore, the engineer should refer to accepted standards and use the terminology provided in the standards. For instrumentation, standards published by the ISA (formerly, Instrument Society of America) are the most relevant. This section uses terms from the ISA wherever possible.

2.0.1 Major issues for selecting sensors

The major issues in sensor selection are summarized in the following. The relative importance of each issue depends upon the specific application; for example, one application might require excellent accuracy, while another might require only moderate accuracy, but high reliability. Generally, we find that the greater the requirements for good performance, the higher the cost for purchase and maintenance. Therefore, we must find the proper balance of performance and cost, rather than always specify the best performing sensor.

ISSUE		COMMENTS
⑤ ⑤ **Accuracy** - Accuracy is the degree of conformity of the measured value with the accepted standard or ideal value, which we can take as the true physical variable. Accuracy is usually reported as a range of maximum inaccuracy. These ranges should have a significance level, such as 95% of the measurements will be within the inaccuracy range. Accuracy is needed for some variables, such as product quality, but it is not required for others such as level in a large storage tank. See Section 24.3 in Marlin (2000) for a discussion on the needs of sensor accuracy.		Accuracy is usually expressed in engineering units or as a percentage of the sensor range, for example: Thermocouple temperature sensor with accuracy of ± 1.5 K. Orifice flow meters with accuracy of ±3% of maximum flow range.
⑤ ⑤ **Repeatability** – The closeness of agreement among a number of consecutive measurements of the same variable (value) under the same operating conditions, approaching in the same direction.		The term "approaching in the same direction" means that the variable is increasing (decreasing) to the value for all replications of the experiment.
⑤ ⑤ **Reproducibility** – The closeness of agreement among a number of consecutive measurements of the same variable (value) under the same operating conditions over a period of time, approaching from both directions. This is usually expressed as non-reproducibility as a percentage of range (span). Often, an important balance is between accuracy and reproducibility, with the proper choice depending on each process application.		The period of time is "long", so that changes occurring over longer times of plant operation are included. Reproducibility includes hysteresis, dead band, drift and repeatability.
⑤ ⑤ **Range/Span** - Most sensors have a limited range over which a process variable can be measured, defined by the lower and upper range values. Usually, the larger the range, the poorer the accuracy, and reproducibility. Therefore, engineers select the smallest range that satisfies the process requirements. We select ranges that are easily interpreted by operating personnel, such as 100-200 °C, but not 100-183 °C.		If a chemical reactor typically operates at 300 °C, the engineer might select a range of 250-350 °C. Since the reactor will be started up from ambient temperature occasionally, an additional sensor should be provided with a range of -50 to 400 °C.
⑤ ⑤ **Reliability** – Reliability is the probability that a device will adequately perform (as specified) for a period of time under specified operating conditions. Some sensors are required for safety or product quality, and therefore, they should be very reliable. Reliability is affected by maintenance and consistency with process environment. Also, some sensors are protected from contact with corrosive process environment by a cover or sheath (e.g., a thermowell for a thermocouple), and some sensors require a sample to be extracted from the process (e.g., a chromatograph).		If sensor reliability is very important, the engineer can provide duplicate sensors, so that a single failure does not require a process shutdown. See Chapter 22 in Marlin (2000) for the use of duplicate sensors in process control.

⑤ ⑤ **Linearity -** This is the closeness to a straight line of the relationship between the true process variable and the measurement. Lack of linearity does not necessarily degrade sensor performance. If the nonlinearity can be modeled and an appropriate correction applied to the measurement before it is used for monitoring and control, the effect of the non-linearity can be eliminated. Typical examples of compensating calculations are the square root applied to the orifice flow sensor and the polynomial compensation for a thermocouple temperature sensor. The engineer should not assume that a compensation for non-linearity has been applied, especially when taking values from a history database, which does not contain details of the measurement technology.		Linearity is usually reported as non-linearity, which is the maximum of the deviation between the calibration curve and a straight line positioned so that the maximum deviation is minimized. See ISA (1979) for further details and several alternative definitions of linearity.
⑤ ⑤ **Maintenance** - Sensors require occasional testing and replacement of selected components that can wear. Engineers must know the maintenance requirements so that they can provide adequate spare parts and personnel time. Naturally, the maintenance costs must be included in the economic analysis of a design.		On-stream analyzers usually require the greatest amount of maintenance. The cost associated with maintenance can be substantial and should not be overlooked in the economic analysis.
⑤ ⑤ **Consistency with process environment** - Most sensors will function properly for specific process conditions. For example, many flow sensors function for a single phase, but not for multi-phase fluid flow, whether vapor-liquid or slurry. The engineer must observe the limitations for each sensor. Some sensors can have direct contact with the process materials, while others must be protected. Three general categories are given in the following. ⑤ **Direct contact** - Sensors such as orifice plates and level floats have direct contact with process fluids. ⑤ **Sheath protection** - Sensors such as thermocouples and pressure diaphragms have a sheath between the process fluid and the sensor element. ⑤ **Sample extraction** - When the process environment is very hostile or the sensor is delicate and performs a complex physiochemical transformation on the process material, a sample can be extracted. Naturally, the parts of the sensor that contact the process must be selected appropriately to resist corrosion or other deleterious effects.		A float can indicate the interface for a liquid level. However, a float is not reliable for a "sticky" liquid. Also, a turbine flow meter can be damaged by a rapid change in flow rate or liquid entrained in a vapor stream. Sensors in direct contact must not be degraded by the process material. The sheath usually slows the sensor response. Samples must represent the fluid in the process.

⑤ ⑤ **Dynamics** - The use of the sensor dictates the allowable delay in the sensor response. When the measured value is used for control, sensor delays should be minimized, while sensors used for monitoring longer-term trends can have some delay.		A greater delay is associated with sensors that require a sample to be extracted from the process. On-stream analyzers usually have the longest delays, which are caused by the time for analysis.
⑤ ⑤ **Safety -** The sensor and transmitter often require electrical power. Since the sensor is located at the process equipment, the environment could contain flammable gases, which could explode when a spark occurs.		Standards for safety have been developed to prevent explosions. These standards prevent a significant power source, oxidizing agent and flammable gas from being in contact.
⑤ ⑤ **Cost** - Engineers must always consider cost when making design and operations decisions. Sensors involve costs and when selected properly, provide benefits. These must be quantified and a profitability analysis performed. In some cases, a sensor can affect the operating costs of the process. An example is a flow sensor. In some situations, the pumping (or compression) costs can be high, and the pressure drop occurring because of the sensor can significantly increase the pumping costs. In such situations, a flow sensor with a low (non-recoverable) pressure drop is selected.		Remember that the total cost includes costs of transmission (wiring around the plant), installation, documentation, plant operations, and maintenance over the life of the sensor. See a reference on engineering economics to learn how to consider costs over time, using principles of the time value of money and profitability measures.

Exercise 2.02 The drawing in Figure 2.02 shows sensors that could be used for monitoring and controlling the process.

How would you select the proper physical principle for each sensor? For example, what principle should be used by flow sensor FC-1; orifice, venture meter, pitot tube, positive displacement, turbine, or other? The resources on this site provide information for making these decisions.

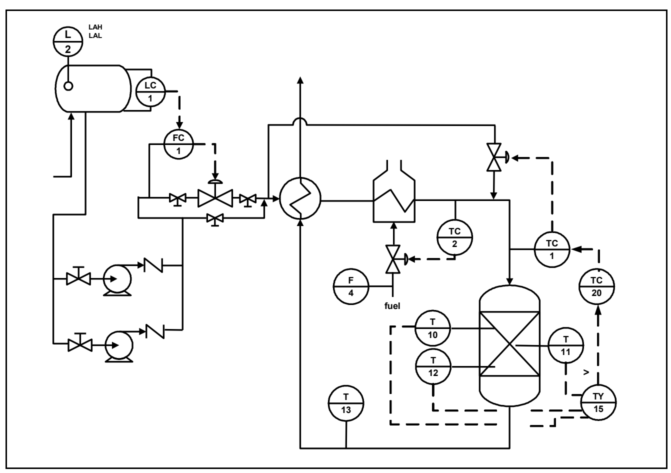


Figure 2.02 Reactor design from Figure 2.1 with sensors added.

2.0.2 Location of measurement displays

The measurement is displayed for observation by plant personnel. Typically, the display uses analog principles, which means that the display presents the measurement as a position in a graphical format, which could, for example, be the height of a slide bar or the position of a pointer. Often, the value is displayed as a line on a trend plot that provides the values for some time in the past. In addition, the measurement can be displayed as a digital number to provide more accuracy for calibration. Finally, measurements that are transmitted to a digital control system can be stored in a historical database for later recall and for use in calculating important parameters useful in monitoring process behavior, for example, reactor yields or heat transfer coefficients.

The engineer must ensure that the measurements are displayed where needed by personnel. Several common approaches are briefly summarized in the following.

- **Local display** - A sensor can display the measurement at the point where the sensor is located. This information can be used by the people when monitoring or working on the equipment. A measurement that has only local display involves the lowest cost, because the cost of transmission and interfacing to a digital system are not required. Note that no history of these measurements is available unless people record the values periodically.
- **Local panel display** - Some equipment is operated from a local panel, where sensors associated with a unit are collected. This enables a person to startup, shutdown and maintain the unit locally. This must be provided for units that require manual actions at the process during normal operation (loading feed materials, cleaning filters, etc.) or during startup and shutdown. Usually, the values displayed at a local panel are also displayed at a centralized control room.
- **Centralized control room** - Many processes are operated from a centralized control room that can be located a significant distance (e.g., hundreds of meters) from the process. The measurement must be converted to a signal (usually electronic) for transmission and be converted to a digital number when interfaced with the control system. A centralized control system facilitates the analysis and control of the integrated plant.
- **Remote monitoring** - In a few cases, processes can be operated without a human operator at the location. In these situations, the measurements are transmitted by radio frequency signals to a centralized location where a person can monitor the behavior of many plants. Typical examples are remote oil production sites and small, safe chemical plants, such as air separation units.

Exercise 2.03 For each of the sensors used in the following list, determine the proper sensor location.		
Orifice sensor used for flow control of the plant feed rate.		Centralized control room

Float sensor used for a high level alarm in a reflux drum.		Centralized control room
Thermocouple sensor used to monitor the temperatures in a fired heater to prevent damage to the equipment.		Centralized control room
Pressure sensor used for the startup of a compressor.		Local control panel and centralized control room
Pressure sensor used to monitor piping for possible plugging.		Local display (unless the plugging could occur rapidly, in which case the display should be in the centralized control room)

2.0.3 The "Smart sensor" revolution

Currently, sensor technology is experiencing a dramatic change. While the basic physics and chemistry of sensors are not changing, sensors are being enhanced by the addition of microprocessors at the location of the sensor. This change makes the following features possible that were not available with older technologies.

- **Digital conversion and transmission** - The "signal" from the sensor is no longer simply a single value representing the measured value. The sensor can transmit additional information, including diagnostics and corrected estimates of a variable based on multiple sensors, e.g., orifice pressures and density. All values can be transmitted digitally, which allows many sensor values to be sent by the same cabling, which reduces the cost of an individual cable for each measurement, as required with analog transmission.
- **Diagnostics** - The sensor can provide sophisticated diagnostics of its performance and warn when a measurement might be unreliable.
- **Signal conditioning** - The sensor can identify unusual signal characteristics and eliminate noise or "spikes" according to methods defined by the engineer.
- **Configuration** - The range of a sensor can be changed quickly to accommodate changes in process operating conditions.

Temperature Measurement

Temperature control is important for separation and reaction processes, and temperature must be maintained within limits to ensure safe and reliable operation of process equipment. Temperature can be measured by many methods; several of the more common are described in this subsection. You should understand the strengths and limitations of each sensor, so that you can select the best sensor for each application.

In nearly all cases, the temperature sensor is protected from the process materials to prevent interference with proper sensing and to eliminate damage to the sensor. Thus, some physically strong, chemically resistant barrier exists between the process and sensor; often, this barrier is termed a sheath or **thermowell**, especially for thermocouple sensors. An additional advantage of such a barrier is the ability to remove, replace, and calibrate the sensor without disrupting the process operation.

Thermocouples: When the junctions of two dissimilar metals are at different temperatures, an electromotive force (emf) is developed. The cold junction, referred to as the reference, is maintained at a known temperature, and the measuring junction is located where the temperature is to be determined. The temperature difference can be determined from the measured emf. The relationship between temperature difference and emf has been determined for several commonly used combinations of metals; the mildly nonlinear relationships are available in tabular form along with polynomial equations relating emf to temperature (Omega, 1995).

> The thermocouple provides a good balance of accuracy, reliability and cost and is one of the most widely used temperature-measuring devices in the process industries.

Resistance Temperature Detectors (RTD): The electrical resistance of many metals changes with temperature; metals for which resistance increases with temperature are used in RTDs. Temperature can therefore be determined from the change in the electrical resistance of the metal wire according to

Effect of temperature on resistance

$$R_T = R_{TO}(1 + \alpha T) \qquad \textbf{(1)}$$

with R_T the resistance, R_{T0} the resistance at base temperature of 0 °C, T the temperature of the sensor (to be determined from R_T) and a the temperature coefficient of the metal. This linear relationship sometimes provides sufficient accuracy, but nonlinear correlations are available for higher accuracy (Omega, 1995). RTDs are commonly used for applications in which higher accuracy than provided by thermocouples is required.

Thermistor: This sensor is similar to an RTD, but applies metals for which the resistance decreases with increasing temperature. The relationship is often very nonlinear, but thermistors can provide very accurate temperature measurements for small spans and low temperatures.

Bimetallic: Metals expand with increasing temperature, and the rate of expansion differs among metals. A spiral constructed of two bonded metal strips will coil (uncoil) as the temperature changes. The changing position of the coil can be detected and used to determine the temperature. This provides a rugged, low cost sensor that is often used for local displays and for on-off temperature control, i.e., a thermostat.

Filled systems: A fluid expands with increasing temperature and exerts a varying pressure on the containing vessel. When the vessel is similar to a bourbon tube, the varying pressure causes a deformation that changes the position detected to determine the temperature.

Table 1. Summary of temperature sensors

Sensor Type	Limits of Application (°C)	Accuracy[1,2]	Dynamics: t (s)	Advantages	Disadvantages
Thermocouple					
type E: chromel-constantan	-100 to 1000	±1.5 or 0.5% for 0 to 900 °C	see note 3	-good reproducibility -wide range	-minimum span of 40 °C -temperature vs. emf not exactly linear -drift over time -low emf corrupted by noise
type J: iron-constantan	0 to 750	±2.2 or 0.75%			
type K: chromel-nickel	0 to 1250	±2.2 or 0.75%			
type T: copper-constantan	-160 to 400	±1.0 or 1.5% for -160 to 0 °C			
RTD	-200 to 650	0.15 + 0.2|T|	see note 3	-good accuracy -small span possible -linearity	-self-heating -less physically rugged -self-heating error
Thermister	-40 to 150	± 0.10 °C	see note 3	-good accuracy -little drift	-highly nonlinear -only small span -less physically rugged -drift
Bimetallic	-	± 2%	-	-low cost -physically rugged	-local display
Filled system	-200 to 800	± 1%	1 to 10	-simple and low cost -no hazards	-not high temperatures -sensitive to external pressure

Notes:

1. Accuracy is measured in °C or % of span, whichever is larger.
2. With RTDs, the inaccuracy increases approximately linearly with temperature deviation from 0 °C.
3. The dynamics depend strongly on the sheath or thermowell (material, diameter, and wall thickness), the location of the element in the sheath (i.e. bonded or air space, the fluid type, and the fluid velocity. Typical values are 2 to 5 seconds for high fluid velocities.

Flow Measurement

Flow measurement is critical to determine the amount of material purchased and sold, and in these applications, very accurate flow measurement is required. In addition, flows throughout the process should the regulated near their desired values with small variability; in these applications, good reproducibility is usually sufficient. Flowing systems require energy, typically provided by pumps and compressors, to produce a pressure difference as the driving force, and flow sensors should introduce a small flow resistance, increasing the process energy consumption as little as possible. Most flow sensors require straight sections of piping before and after the sensor; this requirement places restrictions on acceptable process designs, which can be partially compensated by straightening vanes placed in the piping. The sensors discussed in this subsection are for clean fluids flowing in a pipe; special considerations are required for concentrated slurries, flow in an open conduit, and other process situations.

Several sensors rely on the **pressure drop or head** occurring as a fluid flows by a resistance; an example is given in Figure 1. The relationship between flow rate and pressure difference is determined by the Bernoulli equation, assuming that changes in elevation, work and heat transfer are negligible.

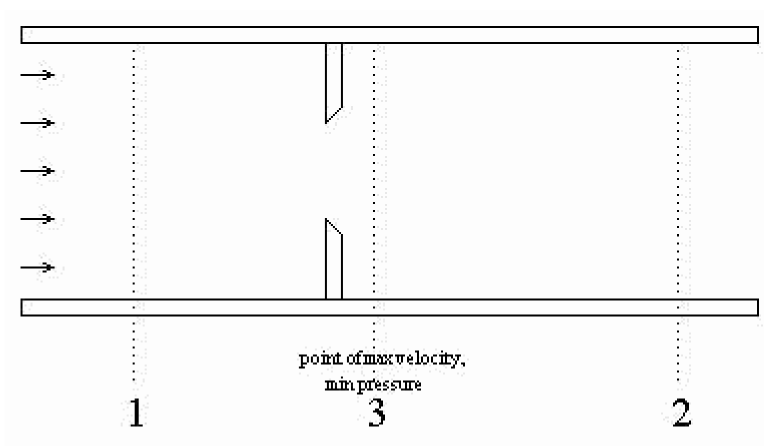


Figure 1. Orifice flow meter

Bernoulli's equation

$$\frac{P_1}{\rho g} + \frac{1}{2g} v_1^2 = \frac{P_3}{\rho g} + \frac{1}{2g} v_3^2 + \Sigma f \qquad (2)$$

where Sf represents the total friction loss that is usually assumed negligible. This equation can be simplified and rearranged to give (Foust et. al, 1981; Janna, 1993)

general head meter equation

$$F_1 = A_1 V_1 = C_{meter} Y A_3 \sqrt{\frac{2(P_1 - P_3)}{\rho(1 - A_3^2 / A_1^2)}} \qquad (3)$$

The meter coefficient, C_{meter}, accounts for all non-idealities, including friction losses, and depends on the type of meter, the ratio of cross sectional areas and the Reynolds number. The compressibility factor, Y, accounts for the expansion of compressible gases; it is 1.0 for incompressible fluids. These two factors can be estimated from correlations (ASME, 1959; Janna, 1993) or can be determined through calibration. Equation (3) is used for designing head flow meters for specific plant operating conditions.

When the process is operating, the meter parameters are fixed, and the pressure difference is measured. Then, the flow can be calculated from the meter equation, using the appropriate values for C_{meter} and Y. All constants are combined, leading to the following relationship.

relationship for installed head meter

$$F = C_0 \sqrt{\frac{(P_1 - P_3)}{\rho_0}} \qquad (4)$$

In the usual situation in which only reproducibility is required, the fluid density is not measured and is assumed constant; the simplified calculation is where the density is assumed to be its design value of r_o. This is a good assumption for liquid and can provide acceptable accuracy for gases in some situations. Again, all constants can be combined (including r_o) into C_1 to give the following relationship.

relationship for installed head meter with constant density

$$F = C_0 \sqrt{P_1 - P_3} \qquad (5)$$

If the density of a gas varies significantly because of variation in temperature and pressure (but not average molecular weight), correction is usually based on the ideal gas law using low cost sensors to measure T and P according to

relationship for installed head meter, gas with constant MW, changing T and P

$$F = C_0 \sqrt{\frac{(P_1 - P_3)}{\rho_0}} \sqrt{\frac{P_0 T}{P T_0}} \qquad (6)$$

where the density (assumed constant at r_o), temperature (T_o) and pressure (P_o) were the base case values used in determining C_o. If the density varies significantly due to composition changes and high accuracy is required, the real-time value of fluid density (r) can be measured by an on-stream analyzer for use as r_o in equation (4) (Clevett, 1985).

The flow is determined from equation (5) by taking the square root of the measured pressure difference, which can be measured by many methods. A U-tube manometer provides an excellent visual display for laboratory experiments but is not typically used industrially. For industrial practice a diaphragm is used for measuring the pressure drop; a diaphragm with one pressure on each side will deform according to the pressure difference.

Note that the pressure in the pipe increases after the vena contracta where the flow cross section returns to its original value, but because of the meter resistance, the pressure downstream of the meter (P_3) is **lower** than upstream pressure (P_1). This is the **"non-recoverable" pressure drop** of the meter that requires energy, e.g., compressor work, to overcome and increases the cost of plant operation. The non-recoverable pressure losses for three important head meters are given in Figure 5.

The low pressure at the point of highest velocity creates the possibility for the liquid to partially vaporize; it might remain partially vaporized after the sensor (called **flashing**) or it might return to a liquid as the pressure increases after the lowest pressure point (called **cavitation**). We want to avoid any vaporization to ensure proper sensor operation and to retain the relationship between pressure difference and flow. Vaporization can be prevented by maintaining the inlet pressure sufficiently high and the inlet temperature sufficiently low.

Some typical **head meters** are described briefly in the following.

Orifice**:** An orifice plate is a restriction with an opening smaller than the pipe diameter which is inserted in the pipe; the typical orifice plate has a concentric, sharp edged opening, as shown in Figure 1. Because of the smaller area the fluid velocity increases, causing a corresponding decrease in pressure. The flow rate can be calculated from the measured pressure drop across the orifice plate, P_1-P_3. The orifice plate is the most commonly used flow sensor, but it creates a rather large non-recoverable pressure due to the turbulence around the plate, leading to high energy consumption (Foust, 1981).

Venturi Tube: The venturi tube shown in Figure 2 is similar to an orifice meter, but it is designed to nearly eliminate boundary layer separation, and thus form drag. The change in cross-sectional area in the venturi tube causes a pressure change between the convergent section and the throat, and the flow rate can be determined from this pressure drop. Although more expensive that an orifice plate; the venturi tube introduces substantially lower non-recoverable pressure drops (Foust, 1981).

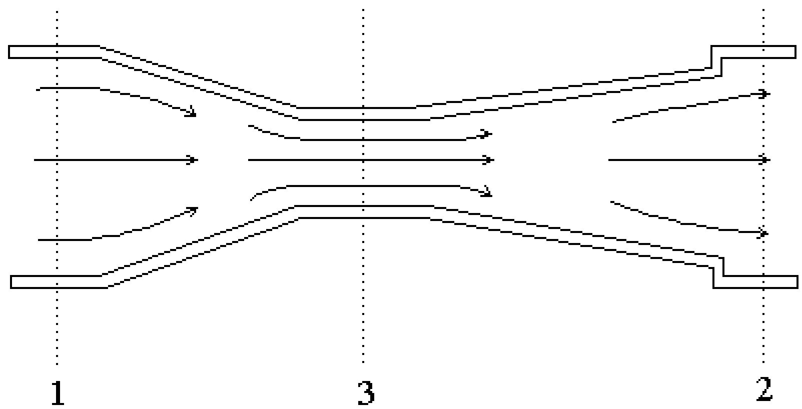


Figure 2. Venturi flow meter

***Flow Nozzle*:** A flow nozzle consists of a restriction with an elliptical contour approach section that terminates in a cylindrical throat section. Pressure drop between the locations one pipe diameter upstream and one-half pipe diameter downstream is measured. Flow nozzles provide an intermediate pressure drop between orifice plates and venturi tubes; also, they are applicable to some slurry systems.

***Elbow meter*:** A differential pressure exists when a flowing fluid changes direction due to a pipe turn or elbow, as shown in Figure 3 below. The pressure difference results from the centrifugal force. Since pipe elbows exist in plants, the cost for these meters is very low. However, the accuracy is very poor; there are only applied when reproducibility is sufficient and other flow measurements would be very costly.

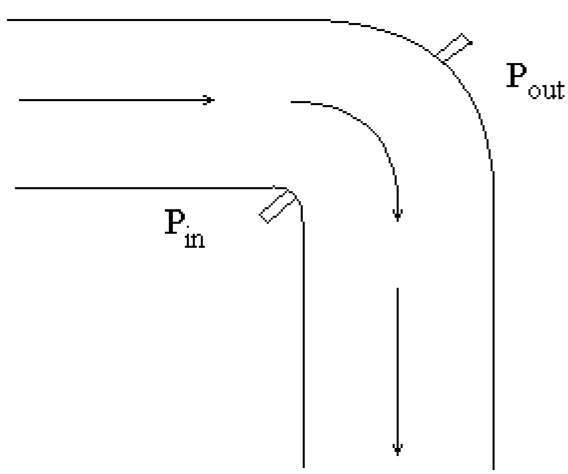


Figure 3. Elbow flow meter.

Pitot tube and annubar: The pitot tube, shown in Figure 4 below, measures the static and dynamic pressures of the fluid at **one point** in the pipe. The flow rate can be determined from the difference between the static and dynamic pressures which is the velocity head of the fluid flow. An annubar consists of several pitot tubes placed across a pipe to provide an approximation to the **velocity profile**, and the total flow can be determined based on the multiple measurements. Both the pitot tube and annubar contribute very small pressure drops, but they are not physically strong and should be used only with clean fluids.

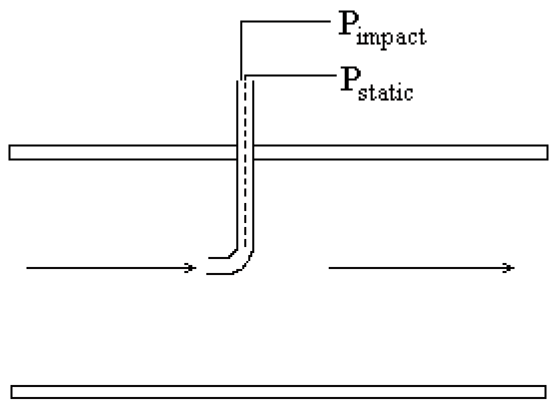


Figure 4. Pitot flow meter.

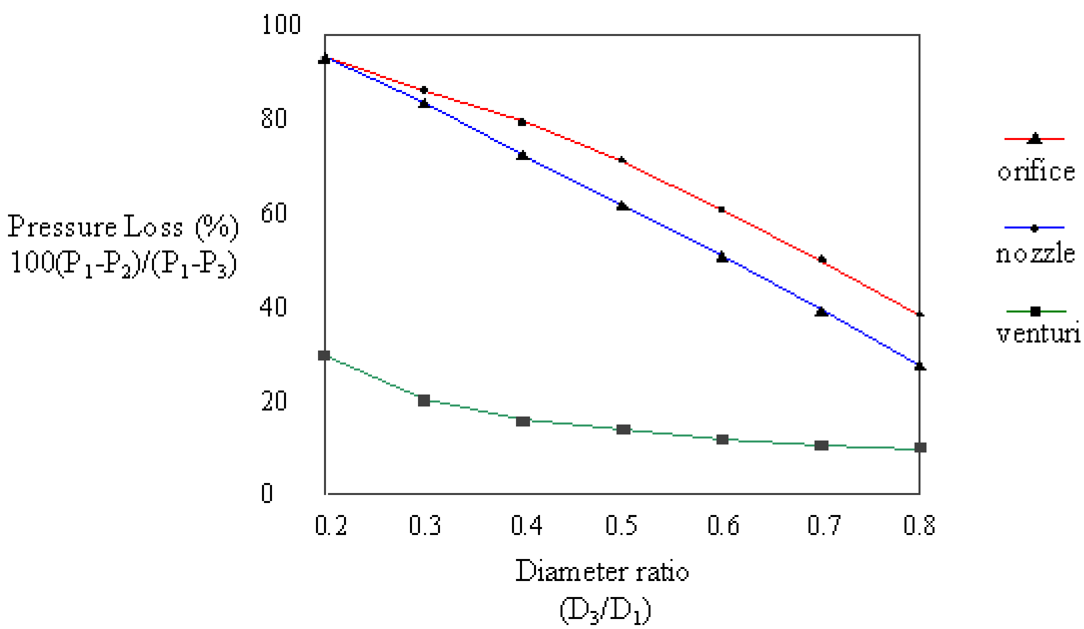


Figure 5. Flow meter non-recoverable pressure losses (Andrews and Williams, Vol 1, 1979)

The following flow sensors are based on physical principles other than head.

Turbine: As fluid flows through the turbine, it causes the turbine to rotate with an angular velocity that is proportional to the fluid flow rate. The frequency of rotation can be measured and used to determine flow. This sensor should not be used for slurries or systems experiencing large, rapid flow or pressure variation.

Vortex shedding **:** Fluid vortices are formed against the body introduced in the pipe. These vortices are produced from the downstream face in a oscillatory manner. The shedding is sensed using a thermistor and the frequency of shedding is proportional to volumetric flow rate.

Positive displacement**:** In these sensors, the fluid is separated into individual volumetric elements and the number of elements per unit time are measured. These sensors provide high accuracy over a large range. An example is a wet test meter.

Table 2. Summary of flow sensors

Sensor	Rangeability[1]	Accuracy[2]	Dynamics (s)	Advantages	Disadvantages
orifice	3.5:1	2-4% of full span	-	-low cost -extensive industrial practice	-high pressure loss -plugging with slurries
venturi	3.5:1	1% of full span	-	-lower pressure loss than orifice -slurries do not plug	-high cost -line under 15 cm
flow nozzle	3.5:1	2% full span	-	-good for slurry service -intermediate pressure loss	-higher cost than orifice plate -limited pipe sizes
elbow meter	3:1	5-10% of full span	-	-low pressure loss	-very poor accuracy
annubar	3:1	0.5-1.5% of full span	-	-low pressure loss -large pipe diameters	-poor performance with dirty or sticky fluids
turbine	20:1	0.25% of measurement	-	-wide rangeability -good accuracy	-high cost -strainer needed, especially for slurries
vortex	10:1	1% of	-	-wide	-expensive

shedding		measurement		rangeability -insensitive to variations in density, temperature, pressure, and viscosity	
positive displacement	10:1 or greater	0.5% of measurement	-	-high reangeability -good accuracy	-high pressure drop -damaged by flow surge or solids

Notes:

1. Rangeability is the ratio of full span to smallest flow that can be measured with sufficient accuracy.
2. Accuracy applies to a calibrated instrument.

Pressure Measurement

Most liquid and all gaseous materials in the process industries are contained within closed vessels. For the safety of plant personnel and protection of the vessel, pressure in the vessel is controlled. In addition, pressured is controlled because it influences key process operations like vapor-liquid equilibrium, chemical reaction rate, and fluid flow.

The following pressure sensors are based on mechanical principles, i.e., deformation based on force.

Bourdon : A bourbon tube is a curved, hollow tube with the process pressure applied to the fluid in the tube. The pressure in the tube causes the tube to deform or uncoil. The pressure can be determined from the mechanical displacement of the pointer connected to the Bourdon tube. Typical shapes for the tube are "C" (normally for local display), spiral and helical.

Bellows **:** A bellows is a closed vessel with sides that can expand and contract, like an accordion. The position of the bellows without pressure can be determined by the bellows itself or a spring. The pressure is applied to the face of the bellows, and its deformation and its position depend upon the pressure.

Diaphragm **:** A diaphragm is typically constructed of two flexible disks, and when a pressure is applied to one face of the diaphragm, the position of the disk face changes due to deformation. The position can be related to pressure.

The following pressure sensors are based on electrical principles; some convert a deformation to a change in electrical property, others a force to an electrical property.

Capacitive or inductance **:** The movement associated with one of the mechanical sensors already described can be used to influence an electrical property such as capacitance affecting a measured signal. For example, under changing pressure a diaphragm causes a change in capacitance or inductance.

Resistive, strain gauge **:** The electrical resistance of a metal wire depends on the strain applied to the wire. Deflection of the diaphragm due to the applied pressure causes strain in the wire, and the electrical resistance can be measured and related to pressure.

Piezoelectric : A piezoelectric material, such as quartz, generates a voltage output when pressure is applied on it. Force can be applied by the diaphragm to a quartz crystal disk that is deflected by process pressure.

Table 3. Pressure sensors

Sensor	Limits of Application	Accuracy	Dynamics	Advantages	Disadvantages
bourdon, "C"	up to 100 MPa	1-5% of full span	-	-low cost with reasonable accuracy -wide limits of application	-hysteresis -affected by shock and vibration
spiral	up to 100 MPa	0.5% of full span	-		
helical	up to 100 MPa	0.5-1% of full span	-		
bellows	typically vacuum to 500 kPa	0.5% of full span	-	-low cost -differential pressure	-smaller pressure range of application -temperature compensation needed
diaphragm	up to 60 kPa	0.5-1.5% of full span	-	-very small span possible	-usually limited to low pressures (i.e. below 8 kPa)
capacitance/ inductance	up to 30 kPa	0.2% of full span	-	-	-
resistive/strain gauge	up to 100 MPa	0.1-1% of full span	fast	-large range of pressures	-
piezoelectric	-	0.5% of full span	very fast	-fast dynamics	-sensitive to temperature changes

Level Measurement

Level of liquid in a vessel should be maintained above the exit pipe because if the vessel empties the exit flow will become zero, a situation that would upset downstream processes and could damage pumping equipment that requires liquid. Also, the level should not overflow an open vessel nor should it exit through a vapor line of a closed vessel, which could disturb a process designed for vapor. In addition, level can influence the performance of a process; the most common example is a liquid phase chemical reactor. Level is usually reported as percent of span, rather than in length (e.g., m). Level sensors can be located in the vessel holding the liquid or in an external "leg" which acts as a manometer. When in the vessel, float and displacement sensors are usually placed in a "stilling chamber" which reduces the effects of flows in the vessel.

***Float* :** The float of material that is lighter than the fluid follows the movement of the liquid level. The position of the float, perhaps attached to a rod, can be determined to measure the level.

Displacement: By Archimedes principle, a body immersed in a liquid is buoyed by a force equal to the weight of the liquid displaced by the body. Thus, a body that is more dense than the liquid can be placed in the vessel, and the amount of liquid displaced by the body, measured by the weight of the body when in the liquid, can be used to determine the level.

Differential pressure: The difference in pressures between to points in a vessel depends on the fluids between these two points. If the difference in densities between the fluids is significant, which is certainly true for a vapor and liquid and can be true for two different liquids, the difference in pressure can be used to determine the interface level between the fluids. Usually, a seal liquid is used in the two connecting pipes (legs) to prevent plugging at the sensing points.

Capacitance : A capacitance probe can be immersed in the liquid of the tank, and the capacitance between the probe and the vessel wall depends on the level. By measuring the capacitance of the liquid, the level of the tank can be determined.

Table 4. Level sensors

Sensor	Limits of Application	Accuracy	Dynamics	Advantages	Disadvantages
float	up to 1 m	-	-	-can be used for switches	-cannot be used with sticky fluids which coat the float
displacement	0.3-3 m	-	-	-good accuracy	-limited range -cost of external mounting for high pressures
differential pressure	essentially no upper limit	-	-	-good accuracy -large range -applicable to slurries with use of sealed lines	-assumes constant density -sealed lines sensitive to temperature
capacitance	up to 30 m	-	-	-applicable for slurries -level switch for many difficult fluids	-affected by density variations

Onstream Analyzers

The term analyzer refers to any sensor that measures a physical property of the process material. This property could relate to purity (e.g., mole % of various components), a basic physical property (e.g., density or viscosity), or an indication of product quality demanded by the customers in the final use of the material (e.g., gasoline octane or fuel heating value).

Analyzers rely on a wide range of physical principles; their unifying characteristic is a greatly increased sensor complexity when compared with the standard temperature, flow, pressure and level (T, F, P, and L) sensors. In many situations, the analyzer is located in a centralized laboratory and processes samples collected at the plant and transported to the laboratory. This procedure reduces the cost of the analyzer, but it introduces long delays before a measurement is available for use in plant operations.

Analyzers can be located near the process equipment to provide real-time measurements of variables for use in plant operations and control. Clearly, the availability of key process variables (*beyond* T, F ,P , and L) provide the possibility of improved dynamic performance leading to increased safety, consistently high product quality and higher profits. In general, these benefits are gained at the expense of higher sensor cost and lower reliability; thus, the engineer should perform an economic analysis considering benefits and costs before deciding to install an on-stream analyzer.

The alternative approach involves feedback control of **inferential variables** (see Marlin, Chapter 17, 1995), perhaps coupled with infrequent laboratory analysis. Both on-stream analyzers and inferential variables are used widely in the process industries; the proper selection of sensor and control technology depends on the costs and benefits for each specific application.

Onstream analyzers utilize many different physical principles, and a survey of these analyzers requires a large body of material, typically at least one full-sized book (e.g., Clevett, 1985). In this section, some of the key factors applicable to many analyzers are reviewed; these factors are independent of the specific physics and chemistry of the analyzer principle. The main general issue is the need for a sample system for many on-stream analyzers.

The purpose of a **sample system** is to extract a representative sample of the fluid, preprocess the material so that the analyzer can perform its function, and dispose of the effluent after the analysis has been completed. A typical sample system is shown in Figure 6. The sample design contributes to achieving the goal of extracting material that represents the total stream properties. Typically, the sample probe (pipe into which the sample flows) has its opening located near the center of the process pipe. Its openings can be arranged to limit the extraction of entrained solids and gases. The flow rate of the sample from the process to the analyzer should be very high even though the analyzer may require only a small amount of material. This “fast loop” of sample flow prevents a long transportation lag, i.e., dead time, in the analyzer sample system. Naturally, this design requires a large amount of material to be sampled, and it should be returned to the process for economic and environmental reasons.

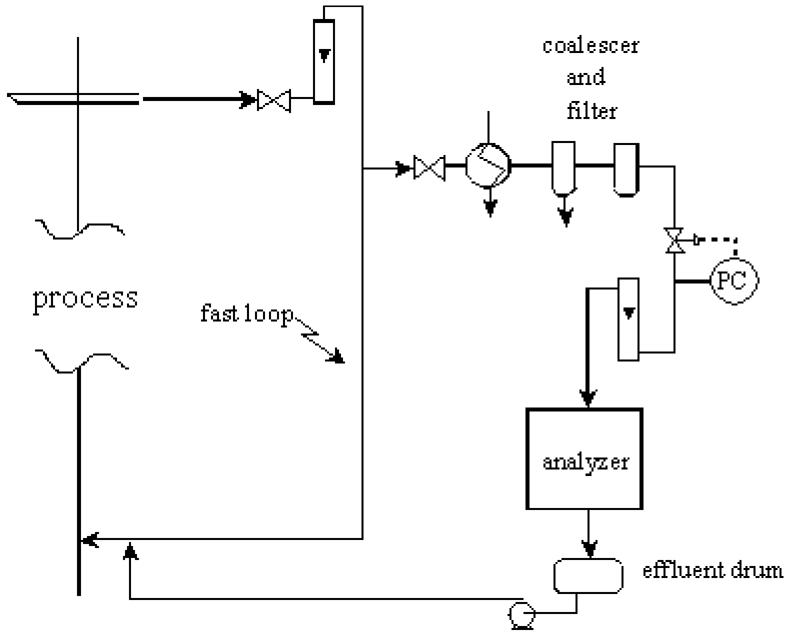


Figure 6. Typical sample system for on-stream analyzer.

A smaller sample for analysis is taken from the fast loop. This sample needs to be **preprocessed or "conditioned"** to ensure that it is acceptable for the analyzer. For example, the sample might be heated to ensure continuous flow of a material that might solidify, or it might be cooled to satisfy limits of the analyzer equipment. In addition, the pressure is regulated to ensure that a large pressure surge in the process is not transmitted to a sensitive analyzer. A pressure regulator is often used; this is a self-contained sensor, proportional controller and valve which provides low cost and reliable protection, but not exact control. Finally, limited physical separation to protect the analyzer may be advantageous; often, a filter is used to remove fine particulate matter, and a coalescer can separate undesired liquid components, for example, occasional water in a hydrocarbon stream.

The **flow** of the stream to the analyzer should be regulated. This flow could be continuous or periodic, depending on the requirements of the analyzer. For example, a chromatogragh requires a periodic flow and provides periodic or discrete values of the measured variable. A continuous stream might be regulated by a rotameter, and a periodic flow could be regulated by electrically operated on/off (solenoid) valves.

All **effluent** material, whether or not it was processed by the analyzer, must be disposed of properly. The best approach is to return all material to the process. This requires either a collection vessel with a pumped return flow or a return to the process at a lower pressure than the analyzer effluent. Environmentally benign material can be vented to the atmosphere or sewer.

Two additional sources of material are common. For startup, shutdown, and pressure testing, a source of clean fluid is required to fill and flush the system. For checking the performance of the on-stream analyzer, a source of fluid with known properties (a **calibration sample**) is provided, and the plant personnel can divert the process sample and send a test sample to the analyzer. This procedure contributes to confidence in the analyzer and much greater use of the measured value in timely decisions.

Finally, the analyzer and sample equipment physically near the analyzer are often located inside an enclosure, an **"analyzer house"**, which can be temperature controlled. This provides shelter for the sensitive electronics and measurement equipment. Also, the shelter provides a barrier between the atmosphere in the plant which might (even very infrequently) contain explosive vapors and the electronic power need by the analyzer.

Clearly, an on-stream analyzer involves a complicated system of flow, pressure and temperature control in addition to the analyzer itself. As a result, the installed cost of an on-stream analyzer can be more than twice the cost of the analyzer alone for laboratory use. An additional cost results from the frequent maintenance of the analyzer; a rough guideline is that one technician working 40 hours per week can maintain about 10-15 on-stream analyzers. However, the measurement and tight control of product quality provide **substantial benefits,** which justify the total cost of many analyzers (for example, Bajek et al, 1987; Black et al, 1987; Marlin et al, 1987).

Control Valves

The most common method for influencing the behavior of chemical processes is through the flow rate of process streams. Usually, a **variable resistance** in the closed conduit or pipe is manipulated to influence the flow rate and achieve the desired process behavior. A valve with a variable opening for flow is the standard equipment used to introduce this variable resistance; the valve is selected because it is simple, reliable, relatively low cost and available for a wide range of process applications. In some cases the valve resistance is set by a person adjusting the opening, like a home faucet. In many cases the valve resistance is determined by an automatic controller, with the valve designed to accept and implement the signal sent from the controller. These are control valves. A multitude of commercial control valves are available; so the goal of this section is to describe the key features of common valves and provide guidance on proper selection and sizing.

The principles of flow control through a restriction in a pipe are presented in textbooks on fluid mechanics (e.g., Janna, 1993) and are briefly summarized here with reference to the example system in Figure 7 taken from Marlin (2000). Naturally, the total pressure drop along the pipe after the valve is the sum of the individual pressure drops, as given in the following equation.

Total pressure drop relationship for pressure downstream of

$$P_2 - P_{out} + \Delta P_e + \sum_{i=1} \Delta P_{Hxi} + \Delta P_{pipe} + \Delta P_{fit} \qquad (7)$$

the valve

As we know the resistance to fluid flow increases as the flow rate increases. Also, the source of the high pressure, here a pump, may be influenced by the flow rate; in this case, the pump head decreases as the flow increases. The relationship between the pressures at the inlet and exit of the valve are shown in Figure 7, and the required pressure drop across the valve is shown as DP_v. Therefore, any desired flow from 0 to 110% of the design valve can be achieved by adjusting the valve opening to provide the required resistance to flow, DP_v. For the example in Figure 7, when the flow is 80% of design, the valve pressure drop is about 40 psi, which can be achieved by adjusting the valve opening for flow to the proper value.

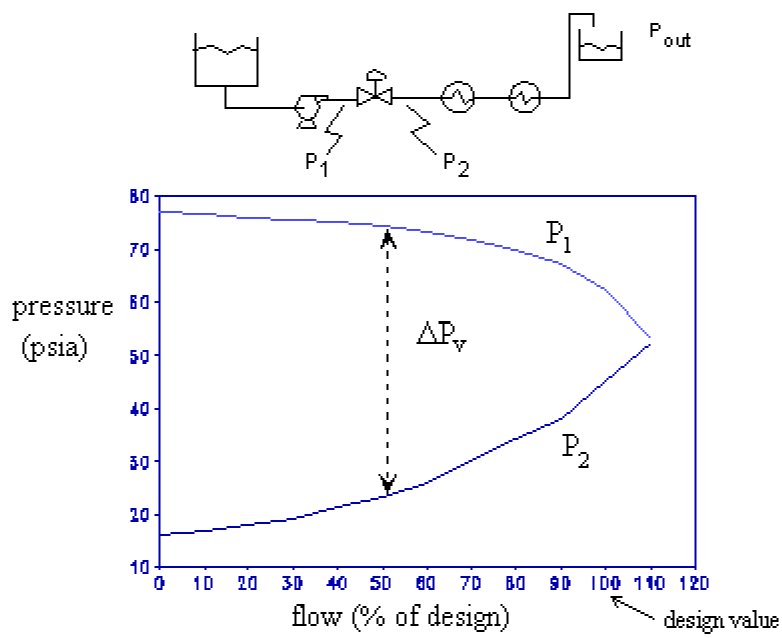


Figure 7. Example flow network with valve pressure drop.

Note that energy is required to raise the stream pressure to P_1 is "lost energy". Therefore, efficient design minimizes the valve pressure drop while providing sufficient variable resistance for good flow regulation. Theoretically, a control valve would not be needed if the supply pressure, in Figure 7 this is P_1, could be varied. Variable speed electrical motors to drive pumps are available for liquid systems, but the added cost and lower efficiencies of these pumps has resulted in the control valve remaining the standard choice for regulating liquid flow (Bauman, 1981). Variable speed steam turbines to drive compressors are commonly applied for gas systems; thus, two methods for adjusting flow in gas systems are common in the process industries: these are:

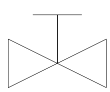
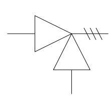
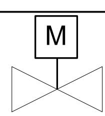
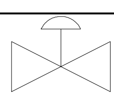
1. manipulating the supply pressure (by the speed of the compressor or pump) and
2. manipulating the variable flow resistance (by a control valve).

We will concentrate on control valves, which are the overwhelming choice for flow control in the process industries

Issues in Valve Selection

Valves are used extensively for affecting the process; we often say that values are the "handles" by which we operate a process. We have many goals in influencing the process; therefore, we use the flow and valve principles in many applications. There are many types of valves. The four most prominent types of valves are summarized below.

Table 3.1.1. Most common applications of valves in the process industries.

Name	Symbol	Power	Typical process application
Block		Manual (by person)	These valves are usually fully opened or closed, although they can be used to regulate flow over short periods with a person adjusting the valve opening.
Safety Relief		Self-actuated (the difference between process and external pressures results in opening when appropriate)	These are located where a high (low) pressure in a closed process vessel or pipe could lead to an explosion (implosion).
On-off		Electric motor	These valves are normally used for isolating process equipment by ensuring that flows are not possible. They can be operated by a person in a centralized control room, who can respond quickly regardless of the distance to the valve.
Throttling control		Usually pneumatic pressure	These valves are typically used for process control, where the desired flow rate is attained by changing the opening of the valve.

This site is concerned with process control. Therefore, this section introduces the main principles for valves used for throttling control. The actuation will be assumed to be by pneumatic pressure, while liquid hydraulics and electronic are used, but less frequently.

Properly operating valves are essential for safe and profitable plant operation. Valve selection can be guided by the analysis of a set of issues, which are presented in this section. Each issue is introduced here with process examples, and details on the issues are provided in the remainder of this site for the most common valves in the process industries.

Exercise 3.1.1 You have just started your first job as an engineer. You supervisor presents you with the process drawing in Figure 3.1.1. She asks you to select valves for this process, specifically the four identified in the figure. "Please have your proposal ready tomorrow for the design review meeting."

Note that the regenerator is a fluidized bed for catalyst, and the riser reactor transports the catalyst with the reacting vapors.

Guidance on selecting valves is provided in this site, with an introduction to the key issues in this section.

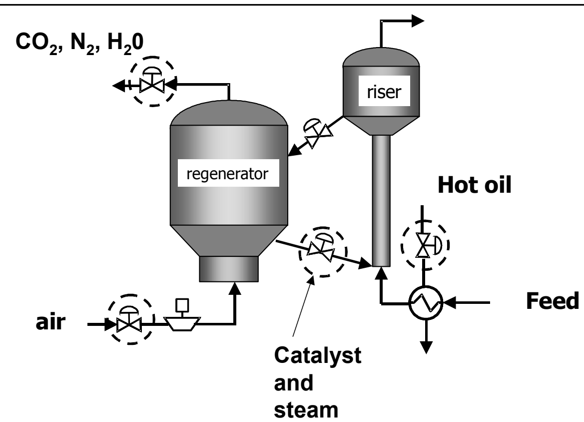


Figure 3.1.1 Fluid catalytic cracking unit in a petroleum refinery.

When defining valve requirements and principles, the engineer should use terminology that has a unique meaning, which is not easily achieved. Therefore, the engineer should refer to accepted standards and use the terminology provided in the standards. For instrumentation, standards published by the ISA (formerly, Instrument Society of America) are the most relevant. This section uses terms from the ISA wherever possible.

3.1.1 Major issues for selecting valves

The major issues in valve selection are summarized in the following. The relative importance of each issue depends upon the specific application; for example, one application might require a low pressure drop, while another might require a large range. Generally, we find that the greater the requirements for good performance, the higher the cost for purchase and maintenance. Therefore, we must find the proper balance of performance and cost, rather than always specify the best performing valve.

ISSUE		COMMENTS
5 **Capacity** - The maximum flow rate through the flow system (pipes, valves, and process equipment) must meet operating requirements. Guidelines are available for calculating the pipe diameter for a desired flow rate, and guidelines are given here for the percentage of the system pressure drop contributed by the valve.		The driving force for flow, i.e., the pressure, must be provided by a centrifugal pump or static pressure difference between vessels.
5 **Range** - The range indicates the extent of flow values that the valve can reliably regulate; very small and large flows cannot be maintained at desired values.		This is often reported as a ratio of the largest to the smallest flows that can be controlled acceptably and is usually in the range of 35 to 50.
5 **Failure position** - Each valve has a power supply that is used to move the valve to its desired opening. The most common power source is air pressure, but hydraulic pressure or an electric motor can be used. The power can be lost for one of two reasons (1) failure in the power source (e.g., air compressor) or (2) a control action that requires the valve to rapidly attain a position that gives a safe process condition. The engineer must define whether the safest condition for each valve is fully open or fully closed. This will be the failure position, and the combination of the actuator and valve body must achieve this position upon loss of power.		We must analyze the entire process, including integrated units to identify the safest conditions. In a few cases, the failure condition is "unchanged". If the air power is lost, air leakage will result in a slow drift to either open or closed.
5 Gain - The gain is $$K_p = \frac{\Delta \text{ measured variable}}{\Delta \text{ valve opening}}$$ In the equation, the measured variable refers to the variable being controlled by the valve adjustments. The gain should not be too small (or the variable cannot be influenced strongly enough to compensate for distrubances) or too large (which would require very small, precise changes to the valve).		Usually, the measured variable is expressed as a percentage of the normal range (or sensor range). If a sensor had a range of 0-200 °C, a five degree change would be 2.5%. A typical range for the gain is 0.5 to 3 (dimensionless).
5 **Pressure drop** - The purpose of the valve is to create a variable pressure drop in the flow system. However, a large pressure drop wastes energy. In some systems, the energy costs for pumping or compressing can be very high, and the pressure drop introduced by the valve should be as small a practically possible.		Here, the key factor is the non-recoverable pressure drop.

⑤ **Precision** - Ideally, the valve would move to exactly the position indicated by the signal to the valve, which is usually a controller output. However, the valve is a real physical device that does not perform ideally. The following factors prevent ideal performance. ⑤ **Deadband** - Upon reversal of direction, the greatest amount that the signal to the valve can be changed without a change to the valve opening (stem position). ⑤ **Resolution** - The smallest amount that the signal to the valve can be changed without a change to the valve opening (stem position). This change is after a change that has overcome deadband and is in the same direction.		Two major causes of non-ideal valve behavior are backlash and stiction. **Backlash** - A relative movement between interacting parts, resulting from looseness, when motion is reversed. **Stiction** - Resistance to the start of motion, usually required to overcome static friction. The valve precision can be improved by the addition of a *valve positioner*. See Section 3.5.
⑤ **Linearity** - The relationship between the signal to the valve (or stem position) and the flow can be linear or non-linear. Either may be desired, since a linear relationship is sought between the signal to the valve and the measured variable (which is not necessarily the flow, it could be a pressure, temperature or other process measurement).		See the discussion on *valve characteristic* in Section 3.3 and in Marlin (2000), Chapter 16.
⑤ **Dynamics** - The valve is part of the feedback system, and any delay due to the valve slows the feedback correction and degrades control performance. Therefore, the valve should achieve the desired opening rapidly.		The actuator must provide sufficient force and the speed of response that can be improved by a *booster*. See Section 3.5.
⑤ **Consistency with process environment** - Each valve body will function for specified fluid properties. Conditions requiring special consideration include slurries, very viscous fluids, flashing and cavitation. In addition, some applications require a tight shutoff. Naturally, the parts of the valve that contact the process must be selected appropriately to resist corrosion or other deleterious effects.		**Flashing -** The pressure drop across the valve can result is partial vaporization of a liquid; this situation is termed flashing when the fluid after the valve remains at least partially vaporized. **Cavitation -** While the fluid at the entrance and exit of a control valve may be liquid, two phases may exist where the flow area is narrowest and the pressure is at its minimum. This temporary vaporization is termed cavitation and can cause *severe damage* to the valve.
⑤ **Cost** - Engineers must always consider cost when making design and operations decisions. Valves involve costs and when selected properly, provide benefits. These must be quantified and a profitability analysis performed. In some cases, a valve can affect the operating costs of the process, where the pumping (or compression) costs can be high, and the pressure drop occurring because of the valve can significantly increase the pumping costs. In such situations, a valve with a low (non-recoverable) pressure drop is selected.		Remember that the total cost includes costs of transmission (wiring around the plant), installation, documentation, plant operations, and maintenance over the life of the valve. See a reference on engineering economics to learn how to consider costs over time, using principles of the time value of money and profitability measures.

Control Valve Body

Many types of valve bodies are available to achieve specific flow regulation behavior. The following description addresses the main valve bodies used in the process industries; key features of each body type are presented after the descriptions in Table 5.

Globe Valve**:** The name "globe" refers to the external shape of the valve, not the internal flow area. A typical globe valve has a stem that is adjusted linearly (up and down) to change the position of the plug. As the plug changes, the area for flow between the plug and seat (opening) changes. Many different seat and plug designs are available to achieve desired relationships between the stem position and flow rate; see the discussion on valve characteristic below. The standard plug must oppose the pressure drop across the valve, which is acceptable for small pressure drops. For large pressure drops, a balanced globe valve is used to enable a valve with small force to open and close the plug.

Ball**:** The restriction for this body is a solid ball which has some part of the ball removed to provide an adjustable area for flow. The ball is rotated to influence the amount of flow. The example ball valve displayed through the link below has a tunnel through the ball, and the ball is rotated to adjust the fraction of the tunnel opening available for flow. Other types of ball valves have different sections removed from the ball to give desired properties.

Butterfly: The butterfly valve provides a damper that is rotated to adjust the resistance to flow. This valve provides a small pressure drop for gas flows.

Diaphragm**:** The diaphragm valve has one surface which is deformed by the force from the valve stem to vary the resistance to flow.

Gate: These valves have a flat barrier that is adjusted to influence the area for flow. These bodies are used primary for hand-operated valves and valves automated for emergency shutoff.

Table 5. Summary of Features for Selected Control Valve Bodies

Valve Body	Advantages	Disadvantages
globe (unbalanced)	-large range -good shutoff	-unbalanced forces -high pressure loss
globe (balanced)	-high capacity -large range	-poor shutoff -high pressure loss

	-balanced forces	
ball	-high capacity -tight shutoff	-moderate pressure drop applications -tends to plug (except segmented ball)
butterfly	-high capacity -low pressure loss -slurry applications	-high torque -large deadband -affects flow through limited range (i.e. 0-60%) -tight shutoff requires special seat material
diaphragm	-slurry applications -corrosion resistant materials	-short diaphragm life -limited pressure and temperature -small range
gate	-tight shutoff	-used only with clean fluids

Valve Characteristic

The relationship between the valve stem position and the flow is defined as the valve characteristic. This relationship with constant (design value) pressure drop is termed the *inherent characteristic*, and the relationship in a specific process in which the pressure drop may vary with flow is termed the *installed characteristic*. Two related units are used for the characteristic; one is flow in gallons of water per minute per stem percent that is used for sizing control valves. The other is percent maximum flow per stem percent which is used to plot typical valve characteristics, for example, Marlin's Figure 16.6 (2000).

The flow through a restriction can often be represented by

relationship for flow through a restiction

$$F = F_{\max}\left(\frac{C_v}{100}\right)\sqrt{\frac{\Delta P}{\rho}} \qquad \textbf{(8)}$$

with, in this expression, the characteristic expressed as a percentage of the maximum flow, and F_{max} is the maximum flow rate with a pressure drop of 1 psi.

A wide range of functional relationships for the C_v can be implemented through the detailed design of the shapes of the plug and seat. Some typical characteristics are shown in Figure 8. The valve characteristic relationship is usually selected to provide a nearly linear relationship between the stem position, which should be the controller output sent to the valve, and the controlled variable. If this goal is achieved, constant controller tuning will be appropriate for the entire range of controller output (and flow rate). To achieve this goal for a process with a constant process gain , a linear characteristic is appropriate, and when the process gain changes with
flow rate, the valve characteristic should be the inverse of the process non-linearity.

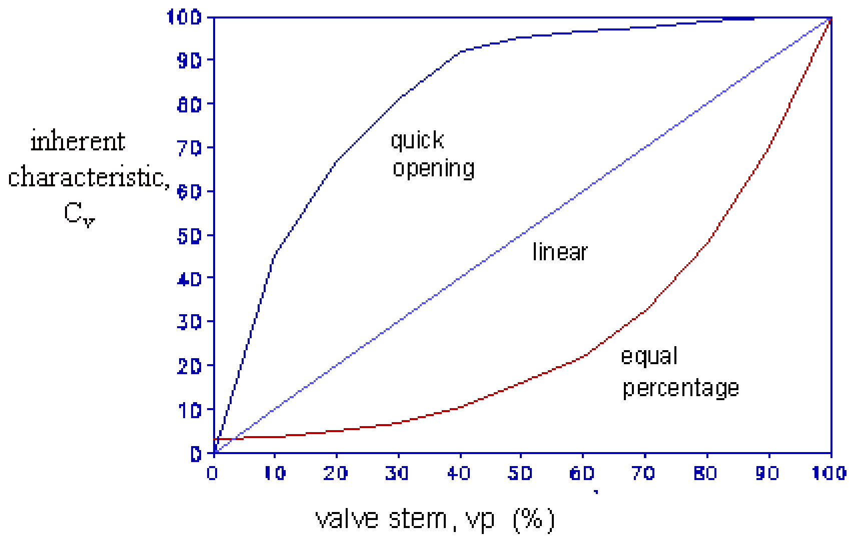


Figure 8. Some typical inherent valve characteristics.

The straightforward procedure for determining a linearizing characteristic is explained in many references, e.g., Marlin (2000) Section 16.5. While some references suggest guidelines for the application of characteristics to specific process applications, the procedure in Marlin (2000) is easy to perform and recommended.

Also, note that linearizing the control loop is not always the most important goal. For example, a valve that must increase the flow from zero rapidly to protect equipment should have a quick opening characteristic, even if this contributes to a nonlinear feedback loop.

Valve Sizing

Control valve sizing involves determining the correct valve to install from the many valves commercially available. The procedure is based on information provided by valve manufacturers, who specify the capacity of their valves using the valve coefficient, C_v. The valve coefficient is defined as the flow of water that will pass through the valve when fully open with a pressure drop of 1 psi. In these tables, the units of C_v are gallons of water per minute per psi$^{1/2}$. The engineer must calculate the desired C_v for the process fluid and conditions by applying appropriate correction factors and select the valve using tables of C_v versus valve stem position and line size provided by the manufacturers

The required flow and pressure drop information used to size a valve is based on the process operations and equipment, and ISA Form S20.50 (ISA, 1992) provides a helpful method for recording the data. The size of the valve depends on the pressure drop across the valve. A general guideline for pumped systems is that the valve pressure drop should be 25-33% of the total pressure drop from supply to the end of the pipe (Moore, 1970). To provide appropriate rangeability, the C_v (flow rate) should be determined for the extremes of expected operation. Typically, a valve should be selected that has the maximum C_v value at about 90% of the stem position; this guideline allows for some extra capacity. The valve should have the minimum C_v at no less than 10-15% stem position, which will give a reasonable rangeability, especially since the accuracy of the characteristic is poor below 10% stem position..

For liquids in turbulent flow, the defining equation is the equation for flow through an orifice, which can be rearranged and supplemented with correction factors.

relationship for liquids in turbulent flow through an orifice

$$F_{liq} = F_P F_R C_v \sqrt{\frac{\Delta P}{G_{liq}}} \tag{9}$$

where

C_v	=	flow coefficient (gallons/min/psi$^{1/2}$)
F_{liq}	=	flow rate (gallons/min)
F_P	=	dimensionless factor accounting for difference in piping due to fittings for piping changes at inlet and outlet; values range from 0.80 to 0.98 and are typically about 0.95 (see Driskell 1983 for details)
F_R	=	dimensionless factor accounting for viscosity effects for liquids; the value is 1.0 for Reynolds numbers greater than 4×10^4 (see Hutchison 1976 for the calculation of the valve Reynolds number and FR)
G_{liq}	=	specific gravity of process fluid at 60 °F (15 °C)
DP	=	pressure drop across the valve (psi)

When the process conditions, including the valve (C_v), are known, equation (9) can be used to calculate the flow. When designing the process, the desired flow is known but the valve is not; equation (9) can be rearranged to calculate the valve coefficient required for the specified conditions.

The pressure decreases as the liquid flows through the valve. The possibility exists for the liquid to partially vaporize due the pressure drop, and this vaporization can have serious consequences for the control valve. Two situations can occur: *cavitation* where the vapor forms and is condensed due to the pressure recovery and *flashing* where vapor remains after the pressure recovery. The effect of vaporization on the flow is shown in Figure 9. Importantly, cavitation involves the collapsing of bubbles that can generate significant forces that will damage the valve components, so that cavitation should be avoided when designing a flow system. This can be achieved by raising the pressure (e.g., higher supply pressure), lowering the stream temperature (e.g., locating upstream of a heater) or using a valve with little pressure recovery.

Flashing occurs when vapor remains downstream of the valve after the pressure recovery. This situation will not result in damage to the valve and is an acceptable design. Special flow models are required for valve sizing when vaporization occurs and can be found is standard references, e.g., Driskell (1983).

For gases and vapors with subsonic flow, the development of the equation is similar but must consider the change in density with an expansion factor and the lack of ideal behavior with the compressibility.

relationship for gases and vapors with subsonic flow through an orifice

$$F_g = NF_P C_v P_1 Y \sqrt{\frac{\Delta P / P_1}{G_g T_1 z}} \qquad \textbf{(10)}$$

where

F_g	=	gas flow rate (std. ft^3/h)
G_g	=	specific gravity of the process fluid relative to air at standard conditions
N	=	unit conversion factor (equal to 1380 for English units)
P_1	=	upstream pressure (psia)
T_1	=	upstream temperature (°R)
Y	=	dimensionless expansion factor which depends on P1/P2 and the specific heat ratio; ranges from 0.67 to 1.0 (see Driskell 1983)
z	=	compressibility factor

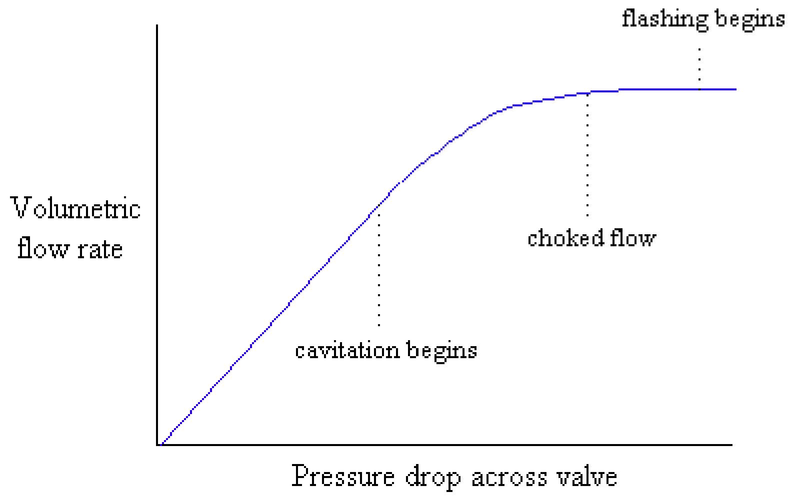


Figure 9. Typical effect of vaporization on flow rate.

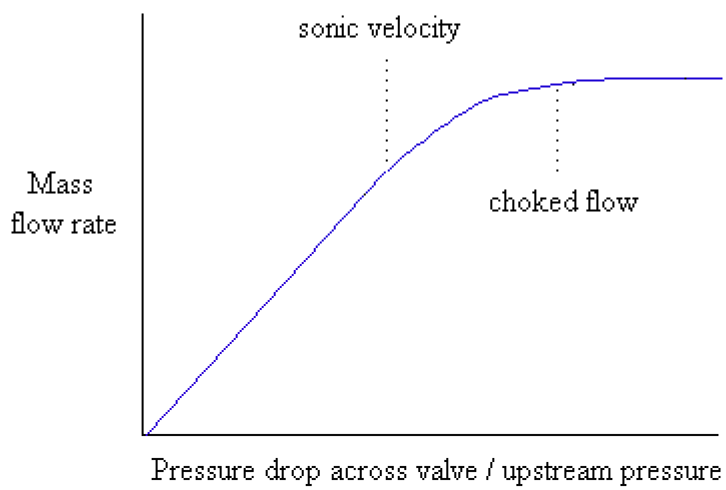


Figure 10. The effect of sonic velocity on flow.

When the pressure drop across the valve is large, sonic flow can occur which will require special calculations for valve sizing (Hutchison, 1976). The general behavior of flow versus pressure drop is shown in Figure 10. When choked flow occurs, the downstream pressure does not influence the flow rate. A rough guideline is that sonic flow does not occur when the pressure drop is less than 42% of the supply pressure. Sonic flow through valves occurs often and does not represent difficulties when the proper valve trim design and materials are used.

Special models are available for unique situations like sonic flow, mixed phase flow, slurries, excessive vibration and noise, and condensation in the valve. See Hutchison (1976) and Driskell (1983) for details.

Additional Control Valve Equiqment

Additional equipment is required for good control valve performance, and a few of the more important items are described in this section.

***Actuator*:** The actuator provides the power that is used to move the valve stem and plug. The power source used in the process industries for the vast majority of the actuators is air because it is safe and reliable. Many actuators are described as diaphragm because the pneumatic signal pressure is transmitted to the actuator volume that is sealed with a flexible diaphragm. As shown in Figure 16, the valve stem is connected to the diaphragm, as is a spring that forces the valve to be either fully opened or fully closed when the opposing air pressure in the diaphragm is atmospheric. The diaphragm pressure is equal to the pneumatic control signal, usually 3-15 psig representing 0-100% of the signal, which forces the diaphragm to distort and moves the valve stem to the position specified by the control signal.

***Booster*:** The flow rate of air in the pneumatic line is not large and significant time may be required to transfer sufficient air into the actuator so that the actuator pressure equals the line pressure. This time slows the dynamic response of the closed-loop system and can degrade control performance. When the delay is significant in comparison with the other elements in the control loop, a booster can be located in the pneumatic line near the valve which increases the volumetric flow rate of air and greatly speeds the dynamic response of the actuator.

Failure position: Major failures of control equipment, such as the break of a pneumatic line or air compressor, lead to a low (atmospheric) pressure for the signal to the actuator. In such situations, where control has been lost, the valve should be designed to attain the safest possible position, which is usually fully opened or closed. The proper failure position must be determined through a careful analysis of the specific process;

usually, the pressure and temperature near atmospheric are the safest. The failure position is achieved by selecting the design in which the actuator valve places the valve stem in its safest position. The design is usually described as fail open or fail closed. Other failure modes can be achieved in response to unusual circumstances, for example, fail to a fixed position and fail slowly to the safe position.

Positioner: The valve is a mechanical device that must overcome friction and inertia to move the stem and plug to the desired position. Typically, the valve does not achieve exactly the position specified by the control signal. This imperfection may not be significant because feedback controllers have an integral mode to reduce offset to zero at steady state. However, the difference might degrade control performance, especially in a slow control loop. A positioner is a simple, proportional-only controller that regulates the measured stem position close to the value specified by the control signal to the valve. For further discussion on positioners, see Hutchison (1976).

Steps in Selecting a Control Valve

The basic steps in control valve selection are presented below.

1. The first step in control valve selection involves collecting all relevant data and completing the ISA Form S20.50. The piping size must be set prior to valve sizing, and determining the supply pressure may require specifying a pump. The novice might have to iterate on the needed piping, pump pressure and pressure drop through the piping network.

2. Next, the size of the valve is required; select the smallest valve C_v that satisfies the maximum C_v requirement at 90% opening. While performing these calculations, checks should be made regarding flashing, cavitation, sonic flow and Reynolds number to ensure that the proper equation and correction factors are used. As many difficulties occur due to oversized valves as to undersized valves. Adding lots of “safety factors” will result in a valve that is nearly closed during normal operation and has poor rangeability.

3. The trim characteristic is selected to provide good performance; goals are usually linear control loop behavior along with acceptable rangeability.

4. The valve body can be selected based on the features in Table 5 and the typical availability in Table 6. Note that the valve size is either equal to the pipe size or slightly less, for example, a 3-inch pipe with a 2-inch globe valve body. When the valve size is smaller than the process piping, an inlet reducer and outlet expander are required to make connections to the process piping.

5. The actuator is now selected to provide sufficient force to position the stem and plug.

6. Finally, auxiliaries can be added to enhance performance. A booster can be increase the volume of the pneumatic signal for long pneumatic lines and large actuators. A positioner can be applied for slow feedback loops with large valves or valves with high

actuator force or friction. A hand wheel is needed if manual operation of the valve is expected.

Table 6. Information on Standard Commercial Control Valves[1]

Body Type	Size (in)	Maximum Pressure (psia)[2]	Temperature (°F)	Capacity[3] $C_d = C_v/d^2$
Globe	1/4 to 16	50,000	cryogenic to 1200	10
Ball	1/2 to 36	2500	up to 1400	30
Butterfly	3/4 to 200	2500	cryogenic to -2200	20
Diaphragm	1/4 to 20	100	-30 to 2200	22

1. Compiled from Andrew and Williams (1980) and Driskell (1983)
2. Higher pressures for smaller sizes and moderate temperatures.
3. The parameter d is the valve connection diameter in inches.

Valve Installation

Many important factors must be considered when designing the physical installation of the control valve. Perhaps the most important is the design of piping for manual bypass. A control valve may require periodic maintenance to correct leaks, noise, vibration, increasing deadband, and so forth. Since a plant shutdown usually involves a large economic penalty, an incentive exists to maintain plant operation while the control valve is being repaired in many, but not all, situations. The bypass system shown in Figure 11 provides the ability to "block" out the control valve while the process flow passes through the manual bypass valve. The performance is best when the design includes 10-20 diameters of straight run piping in the inlet and 3-5 diameters in the outlet. An operator must close the block valves and manipulate the bypass valve to achieve some desired operating condition, such as flow rate or temperature. For a typical globe valve, the valve should be installed so that the stem moves vertically with the actuator above the valve. In addition, the valve should be located with enough clearance from other equipment so that maintenance can be performed on the valve.

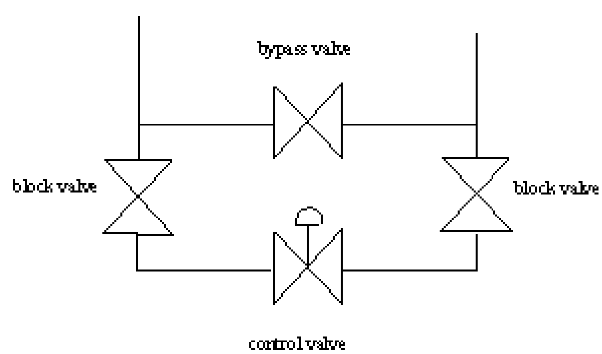


Figure 11. Typical control valve installation

Control valves are used to affect the flow rate in a pipe, i.e., they are used to throttle flow. Control valves do not provide reliable, tight closure, so that some small flow rate can be expected when the valve is "fully closed". The amount of leakage depends upon the valve body and the fluid.

Control Signal Transmission

Most process control systems involve a structure of distributed equipment, with sensors and valves at the process equipment and the control calculations and displays located in a remote, centralized facility. Therefore, values of key variables must be communicated between the sensors, calculations and valves (or other final elements). Schematics of typical control systems with analog and digital control are given in Figure 4.0.1.

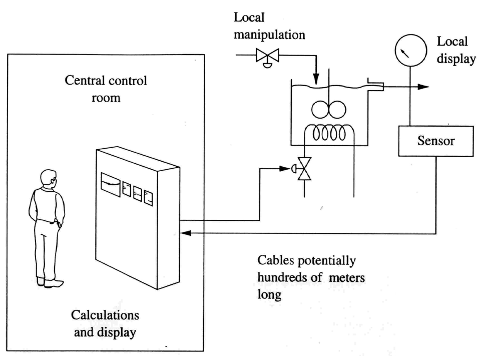


Figure 4.0.1a Distributed control with analog control calculations.

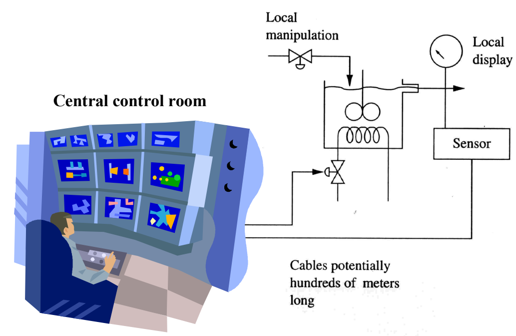


Figure 4.0.1b. Distributed control with digital control calculations

Not all sensors and valves require signal transmission. Sensors with local displays and valves requiring manual operation have no signal to transmit. However, many (most) sensors and valves require signal transmission, so that personnel in a single location can manage the entire process. Reliable, accurate and rapid signal transmission is essential for excellent process control.

A schematic of the equipment in a control loop, which presents the most typical signal transmission, is given in Figure 4.02. The most common equipment in the loop is described in this paragraph, while some other possibilities are shown in the figure. The process variable is measured using a sensor applying technology presented in Section 1. Typically, the measured value is converted to a "signal" that can be transmitted. The signal can be electronic or digital, as will be covered in subsequent sections; this conversion is achieved at the location of the sensor. The signal is sent from the transmitter to the control room, where it can be employed for many purposes, such as display to control as shown in Figure 4.02. When the signal is used for control, the value of the controlled variable (signal from the sensor) is used by the controller to determine the value of the controller output. The controller output is transmitted to the final element, which is shown as a valve in Figure 4.02, but could be switching a motor on/off or other automated action. For a control valve, the stem position is affected by air pressure to a pneumatic actuator; therefore, the electrical signal from the controller must be converted to air pressure signal. This conversion is achieved at the valve. The valve stem moves the valve plug, changes the resistance to flow, and the flow rate changes.

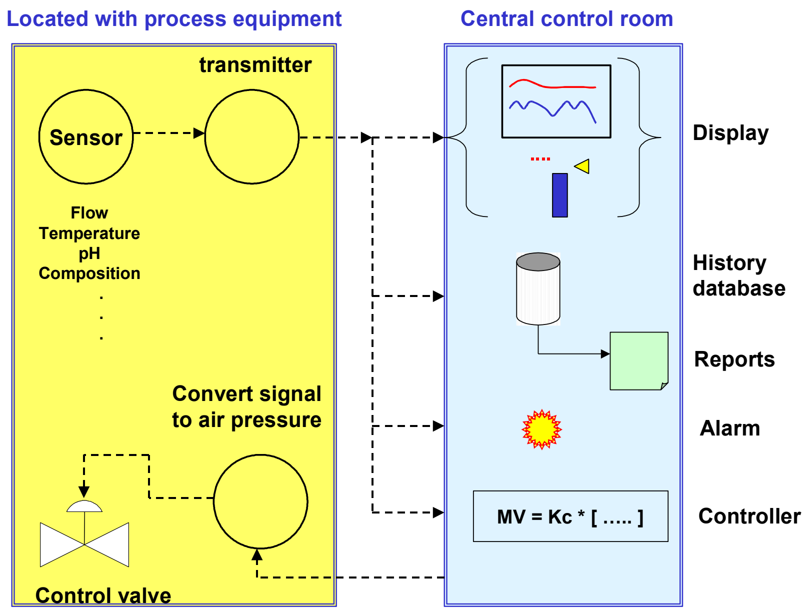


Figure 4.0.2. Schematic of the key elements required for monitoring and control.

Exercise 4.0.1 The preceding text noted that local sensors and valves do not require signal transmission. There are cases in which feedback control is provided locally, which eliminate the need for signal transmission.

a. Describe why feedback control would be implemented locally. Give advantages and disadvantages for this approach.
b. Describe examples of equipment used to implement local feedback control.

Exercise 4.0.2 Key elements in a control loop are shown in a piping and instrumentation (P&I) drawing.

a. Sketch a typical control loop as it would appear on a Piping and Instrumentation drawing.
b. Define the difference between a "conceptual" and "detailed" P&I drawing, and explain the differences in the presentation of a control loop in each.

New Technology for Signal Transmission initiates Revolution in Process Control

Learning the basics of signal transmission is becoming a greater challenge than it was in previous decades. The challenge results from the recent, rapid change in technology for control signal transmission. From the inception of process control until the 1990's, each signal involved the value a single variable transmitted in only one direction by pneumatic, electronic, or hydraulic techniques; these are termed *analog signals*. This lack of two-way communication limits the capability of the system. For example, when the controller output value is sent to the valve (more correctly, to the i/p converter), no information can be returned by the same wire, so that the control system has no confirmation that the valve stem has moved.

Recently, new technology is being used for the signal transmission using *digital communication*, which has much greater flexibility for transmitting multiple variable values, communicating to both directions and performing calculations. Two-way communication and computation at any element in the system (not just the controller) provides the opportunity for diagnostic information to be communicated about the performance of the sensor and final element. Diagnostics can be used to schedule maintenance, when the maloperation is not too serious, such as a slow drift from good accuracy. When the fault prevents proper control, the system can immediately stop the operation of the control loop and alarm the operations personnel.

Since control equipment has a long lifetime, practicing engineers will encounter many examples of both analog and digital transmission technologies and therefore, must have a basic understanding of both.

Caution: Because of the rapidly changing technology, many transmission structures are possible, and new technology and features appear frequently. This brief coverage simplifies the situation to present the important issues applicable to two of the typical transmission approaches. Thus, the material provides a basis for initially learning the control equipment in a loop and the functions provided by transmission. Further study and experience is required to be able to design, select equipment for and procure a proper industrial transmission system.

Transmission Issues

Signal transmission is an integral part of every feedback control loop. We must recall, "a chain is only as strong as its weakest link". Therefore, excellence process control performance requires the signals to be transmitted between loop elements reliably, rapidly and accurately. To establish a basis for learning methods for signal transmission, we briefly review transmission issues in this section. The relative importance of each item depends on the specific application. For example, fast response is required for controlling a mechanical system with rapid process dynamics, while high reliability is required for a safety-critical application.

Many methods for communication are in common use in society, e.g., radio and television transmissions. The following material is restricted to applications of signal transmission for automatic control in the process industries.

The major issues in signal transmission for control are summarized in Table 4.1.1.

Table 4.1.1. Control Transmission Issues

ISSUE		COMMENTS
5 **Accuracy and reproducibility -** The signal transmission should be more accurate than the sensor and final element, so that no degradation results from the transmission. Here, accuracy can be taken to mean a difference in the signal value from its exact value.		Recall that the transmission occurs in the feedback loop, so that inaccuracy will affect the performance of feedback control. Field calibration must be possible without removing the equipment or compromising the safety protection.
5 **Noise sensitivity -** The signal can be influenced by "noise", including electrical signals from other devices. The system must be designed to reduce the effects of noise.		
5 **Reliability -** The failure of a signal transmission results in the loss of feedback control. For safety-critical signals, a backup (parallel) transmission path may be required.		Because the equipment may be located outdoors, it must be physically rugged and be resistant to water and significant changes in temperature. In a typical loop, the elements are connected in series. The reliability of a series of elements is the product of the reliabilities of each element. The power supplies are important potential sources of failures that can affect many signals simultaneously.
5 **Dynamics -** Signal transmission is part of the feedback loop, and any delays degrade control. The transmission should be much faster than other elements in the loop.		Transmission by electronic analog or digital signal is much faster than the dynamics of a typical process element.
5 **Distance -** In large plants, signals can be transmitted several thousand meters.		Physical connections have distance limitations. For very long distances, telemetry is used; however, reliability is sacrificed, so that this method is normally restricted to monitoring, with control implemented locally.
5 **Interoperability -** We want to be able to use elements manufactured by different suppliers in the same control loop. For example, we want to use a sensor from supplier A, a controller from supplier B, and a valve from supplier C. To achieve this "interoperability", international standards must exist for the signals being transmitted between elements, i.e., sensors,		Standards are easily achieved for analog signals, 4-20 mA (electronic) and 3-15psig (pneumatic). At the present time, several competing standards exist for digital transmission.

controllers, and valves.		
⑤ **Safety -** Naturally, the signal must not compromise the safe operation of the system. Since power is used for the transmission, special considerations are required to prevent combustion or explosion.		The power supplied must be low or a dangerous event must be contained within a controlled environment (enclosure). In addition, a high voltage or current caused by a circuit fault must not be transmitted to a process area where a fuel is present.
⑤ **Diagnostics and configuration -** Ideally, the signal should be able to communicate several values, for example, ⑤ confirmation that the signal is being transmitted (live zero) ⑤ confirmation that the signal was received (echo) ⑤ configuration values required for sensors and final elements, e.g., sensor zero and span values.		More limited (analog) systems could provide many independent signals for every variable. However, this approach would be very costly because a separate cable would be required for each signal and is not used in practice. Digital transmission can communicate many values related to each variable, e.g., process measurement.
⑤ **Cost -** Typically, several transmission methods will satisfy basic requirements, so that benefits and costs must be evaluated to determine the best choice.		Remember that the total cost includes costs of installation, documentation, plant operations, and maintenance over the life of the sensor. See a reference on engineering economics to learn how to consider costs over time, using principles of the time value of money and profitability measures.

Key question: What should be transmitted?

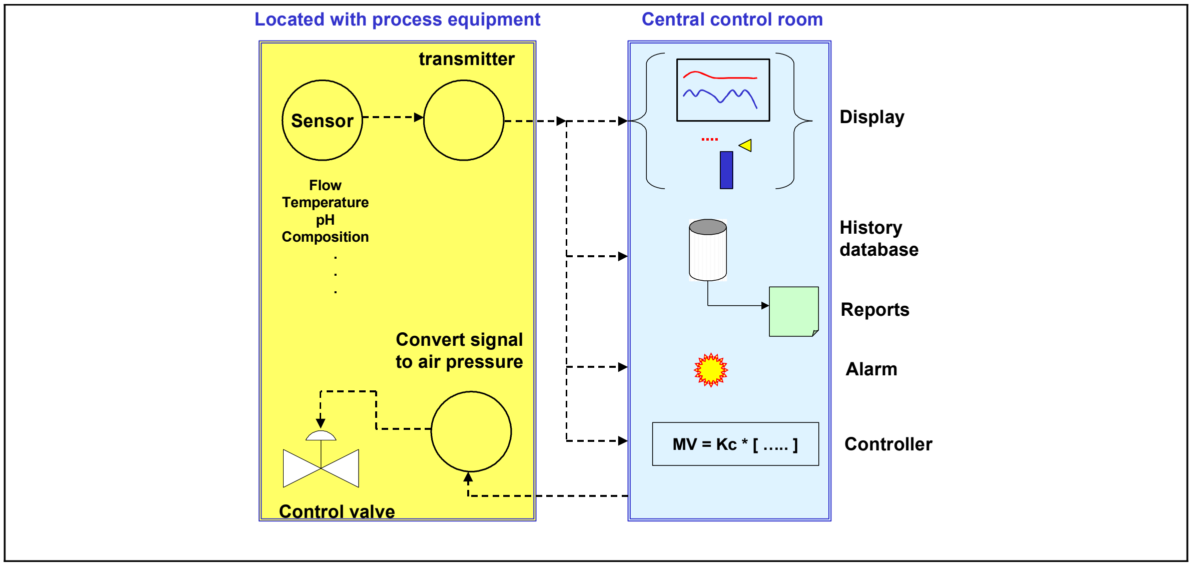
A major issue in signal transmission is the variable(s) transmitted. In analog systems, this choice is limited to a single variable, so that the choice is obvious. The sensor sends its measured variable to the controller and the controller sends its calculated output to the valve.

With digital transmission, many variables can be transmitted essentially simultaneously. Therefore, we have the possibility for many variables. In addition, we can have two-way transmission, with some transmission in the directions opposite to the arrows in Figure 4.02. As we will see, benefits for digital transmission accrue to a large extent from the ability to transmit additional variables, not from simply duplicating the functions available with analog transmission.

Exercise 4.1.1. Consider the typical control loop in Figure 4.0.2, repeated below.

Suggest variables that can be transmitted in either direction between the following elements in a control system via digital transmission. In answering this question, you can assume that any variable or parameter can be transmitted without significant delay.

a. The sensor and control system.
b. The control system and the valve.



Analog Signal Transmission

We have learned that feedback control consists of a loop with common elements, for example, a sensor, control calculation, and final element. Generally, the three elements are distinct physical entities and can be located at significant distances from each other. Therefore, transmission of signals, or information, between the elements is essential.

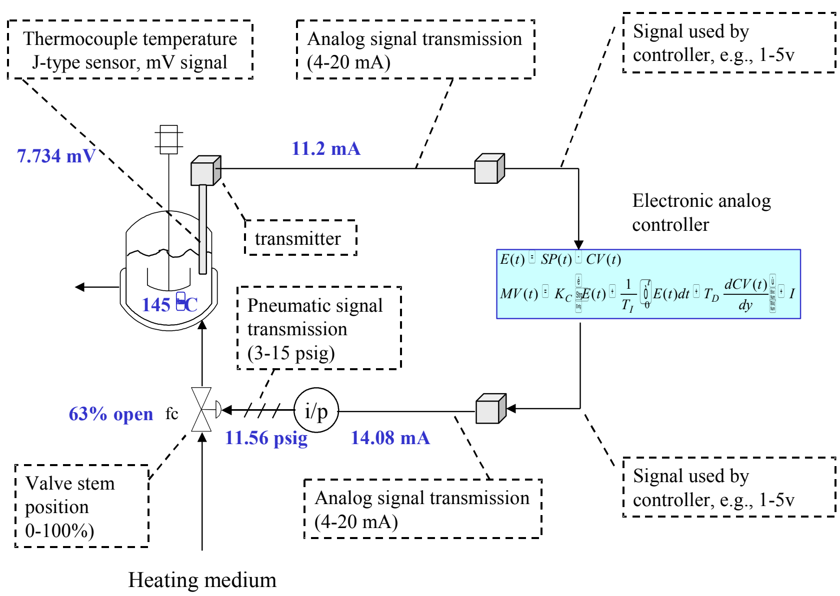


Figure 4.2.1. Typical analog signal transmission with analog control calculation.

Analog signal transmission was the only method for communication in process control from its inception until the later part of the twentieth century. By "analog", we mean that the value of a physical variable is an "analogy" to the control system variable. For an example, consider the stirred tank process in Figure 4.2.1 in which the thermocouple measures the liquid temperature in the stirrer tank. When the temperature changes, the millivolt signal from the thermocouple also changes; therefore, the millivolt is an analog signal representing the liquid temperature. The relationship between the hot junction temperature and the millivolt signal for each thermocouple design (here, a J-type) can be found in standard references (Omega Themocouple, 2006). The millivolt is converted into a signal for transmission to a control system for display, recording, and control.

The basic equipment in a loop is shown in Figures 4.2.1 and 4.2.2. The measured value from the sensor is converted to the appropriate signal (physical variable and value) by a transmitter. The converted signal is sent to the control system. The controller can be analog (continuous) or digital (discrete), and naturally, the conversion of the signal for the controller must be appropriate for the type of controller. The controller provides an output that must be converted to a signal for transmission to the final element. The figures show an additional conversion that provides pneumatic pressure to the actuator of a control valve. This design is appropriate for electronic analog signals being transmitted to a pneumatic valve, which is typical in the process industries. However, we recognize that other situations occur, for example, the final element could be speed of an electric motor, which would not require conversion to a continuous pneumatic signal.

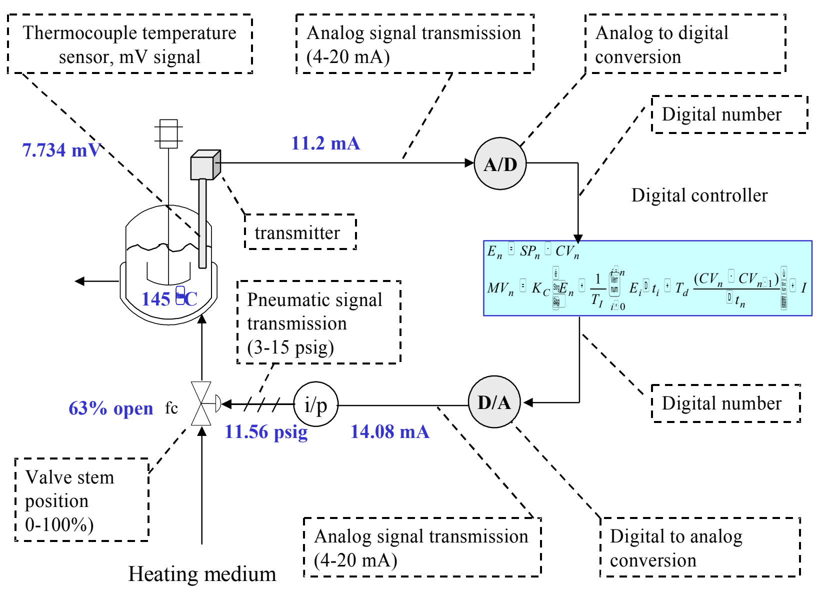


Figure 4.2.2. Typical analog signal transmission with digital control calculation.

In the process industries, the following analog signals are in use.

- Physical position (connecting rod)
- Hydraulic pressure
- Pneumatic (air) pressure (3-15 psig)
- Electronic (4-20 mA DC)

In this section, we will restrict the discussion to electronic signals, except for the signal to pneumatic control valves. The other three signals have limitations in distance, but find application in specialized, simple control equipment. The standard electronic analog signal used internationally is 4-20 mA (milliamp) to ensure interoperability.

The use of an analog signal to represent a sensor value involves the concept of a scaled variable that establishes the relationship between a specific value of milliamps and the control system variable. To understand, consider the example given in the following and shown in Figures 4.2.1 and 4.2.2.

> Temperature = 145 °C
> Temperature sensor/transmitter range = 100 to 200 °C
> Therefore, the transmitter zero = 100 °C and the span is 200-100=100 °C
> Sensor signal range = 4 to 20 mA

We note that the sensor/transmitter provides a valid indication of temperature within its range. If the temperature exceeds the range, the reported value remains at the appropriate limit, either low or high. The use of a limited range improves the accuracy of the measurement and signal transmission. The transmitter provides the value of milliamps (mA) for transmission, according to the following calculation of the scaled variable, which represents a *linear* relationship between process variable and signal value.

$$PV = Zero + Span * \frac{(Signal_{sensor} - 4)mA}{(20 - 4)mA} \tag{4.2.1}$$

$$PV_{scaled} = \left[\frac{(Signal_{sensor} - 4)mA}{(20 - 4)mA} \right] 100 \tag{4.2.2}$$

with

PV	= the process variable (engineering units)
PV_{scaled}	= the process variable (scaled variables in % of span)
Zero	= the low value of the range of the process variable (engineering units)
Span	= (high - low) values of the process variable range (engineering units)
$Signal_{sensor}$	= transmitted signal in milliamps

Applying this concept to the temperature example using equation (4.2.1)

$$\begin{aligned} &145^\circ C = 100^\circ C + 100^\circ C * (Signal - 4)mA/(16mA) \\ &Signal = 11.2mA \end{aligned} \tag{4.2.3}$$

Also, the value of PV_{scaled} is 45%.

Equations (4.2.1) and (4.2.2) are valid when the process variable has a value within the range of the sensor. The signal is never less than 4 mA nor greater than 20 mA. Therefore, the engineer must take care when specifying sensor ranges; ranges that are too small to achieve improved accuracy will fail to provide a useful valve during disturbances. Also, care is needed interpreting a signal at either limit of the sensor range.

In many controllers, including all analog (continuous controllers), the calculations are performed in scaled variables, i.e., PV_{scaled}. See Marlin (2000) Chapter 12 or other references for further discussion of the use of scaled variables.

Note that the electronic analog signal contains no information about the process variable type (whether it is temperature, pressure, etc.), variable identification (heat exchanger outlet, reactor bed, etc.) or the transmitter range. Therefore, thorough documentation, calibration and verification are required when installing control equipment so that a signal can be correctly interpreted where it is received.

The transmitter generally is faster and more accurate than other elements in the loop, and the signal transmission is essentially instantaneous and without error. Generally, the sensor and transmitter are purchased as a single unit from the instrument supplier. Therefore, dynamics and accuracy specifications are typically provided for the integrated sensor and transmitter. Typical values are given in Section 2 on sensors.

The control calculation can be analog or digital. If digital, the signal is converted from a current to a digital representation by an analog to digital (A/D) converter. Sampling rates can be over 100,000 samples per second, which is much higher than required for most process applications. However, control of high-speed machinery requires very high sampling rates. The A/D accuracy depends on the equipment design and the number of bits in the digital (binary) representation of the number. The accuracy is determined by the last bit, because signal change smaller in magnitude than the smallest bit does not change the value of the binary number. The accuracy is approximately 1 in 2^n-1, where n is the number of bits in the binary number and is usually between 10 and 13. Typically, commercial process control A/D equipment has an accuracy between 1:1024 to 1:8192 (expressed as inaccuracy in fraction of sensor span) and a conversion time much faster than process elements in the loop (0.1 ms) (Liptak, 1999). Because of the speed and accuracy, the A/D conversion has little effect on a typical feedback loop controlling pressure, level, temperature, etc.

The result of a control calculation is sent to the final element. If the control calculations are performed via digital computation, the result must be converted using a digital to analog (D/A) converter. Typically, commercial process control D/A equipment has an accuracy of about 1:1024 (expressed as inaccuracy in fraction of output span, 0-100%) and a conversion time much faster than other elements in the loop (Liptak, 1999). Again, the D/A conversion has little effect on a typical feedback loop controlling pressure, level, temperature, etc.

Typically, the controller output in percent is transmitted to a throttling control valve, i.e., a valve whose opening is adjusted as a continuous variable to determine the flow. Often, the value transmitted is the result of the famous PID calculation. The signal transmitted is the same percentage of the range of the electronic signal. Recalling that the electronic signal is 4-20 mA, the conversion from controller output to current is given in the following linear relationship.

$$Signal_{valve} = Zero_{signal} + MV \frac{(20 - 4)mA}{(100 - 0)\%} \tag{4.2.4}$$

with

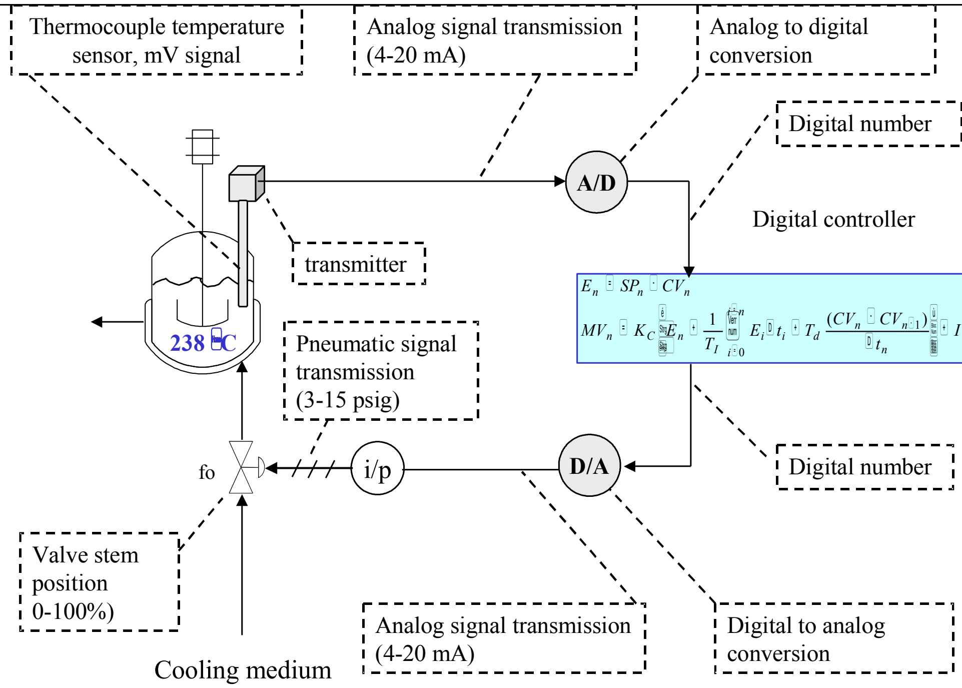
MV	= controller output in % (0-100)
Zero $_{signal}$	= 4 milliamp (live zero)
$Signal_{valve}$	= signal from controller to valve (i/p converter) in mA (4-20)

For example, if the controller output (MV) were 63%, the signal transmitted would be 14.08 milliamp.

The electronic signal is converted to pneumatic because most control valves employ air pressure to provide the force needed to move the stem position. Using air eliminates the need for electric motors, which could be sources of hazardous power and equipment faults. Naturally, a reliable source of dry compressed air must be provided and distributed throughout the process to every valve actuator. Again, an international standard signal has been agreed; for pneumatic signals, the standard is 3-15 psig. When applying this standard to the example above, the input to the i/p converter would be 14.08 mA and the output would be 11.56 psig. Ideally, the valve stem position for the signal of 11.56 psig would be 63%; the actual position would not be exactly 63% because of calibration inaccuracies and friction.

Exercise 4.2.1 Calculate all signals with units for the system in Figure 4.2.3. You do not have to determine the binary values for the digital numbers, and my assume that all equipment functions perfectly (which does not happen in real life!).

Thermocouple type: K
Temperature transmitter range: 150-400 °C
Set point (SP): 245 °C
Controller tuning: $K_c = 0.62\ \%/°C$, $T_I = 12\,\text{min}$, $T_d = 0\,\text{min}$



Past controller values:

$$CV_{n-1} = 237°C, \quad \sum_{i=0}^{i=n-1} E_i \Delta t = 75.5(\text{min}\,°C), \quad I = 30\%, \quad \Delta t = 0.50s$$

Figure 4.2.3. Loop schematic for Exercise 4.2.1.

Exercise 4.2.2 The electronic signal from the sensor/transmitter to the controller has a value of 1.3 mA. What can you conclude from this value? What is the proper action to be taken by the controller? Can this action be automated?

Exercise 4.2.3 Typical values are given for measured variables in Figure 4.2.4.

a. Propose initial values for sensor ranges for the measured variables.
b. Specify additional information that you would need before you were confident that the

values you estimated in part (a) were appropriate for the plant.

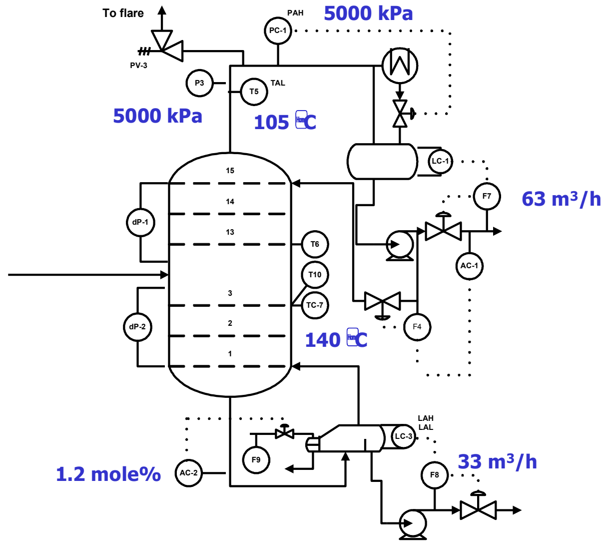


Figure 4.2.4. Distillation sensors with design values of selected variables.

Exercise 4.2.4 For each of the following sensors, describe the variable measured by the sensor. In addition, define the calculations required to determine the process variable used for control from the signal from the sensor.

a. Orifice flow sensor
b. Thermocouple
c. Level by pressure difference
d. Pressure

Digital Transmission

Electronic analog transmission has been employed successfully for many decades, so that little benefit would be gained from replacing the same functions via digital communication. Therefore, digital communication has been developed to provide additional capabilities at reasonable cost. In this section, we will restrict the discussion to digital communication linking elements in the real-time control loop. The enhanced transmission must be complemented with increased capabilities in the loop elements, i.e., the sensor and final element. These will be "smart", that is, they will have memory, programming, and computing capabilities. This design for digital transmission provides distributed computation, which is the true advantage for replacing analog with digital transmission.

The term **fieldbus** refers to the use of digital transmission and distributed computing for real-time process control. Several system designs exist for fieldbus, and only some features common to most designs are introduced here.

A typical fieldbus structure is shown in Figure 4.3.1. One important difference from analog transmission is immediately apparent. In analog transmission, individual cables link each sensor and final element to the controller. The multitude of cables is very expensive but has the advantage of limited effect from a single cable fault. On the other hand, the fieldbus structure has one (or a few) cable for the data transmission for all sensors and final elements. This design is much less costly to purchase and install but has the disadvantage of greater effects from a cable fault.

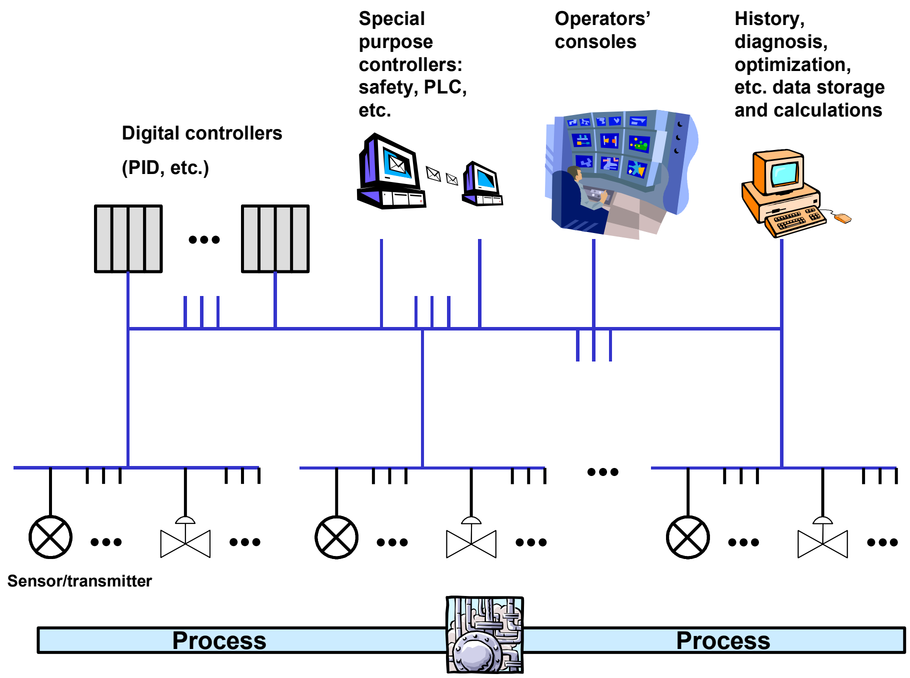


Figure 4.3.1. A typical fieldbus control system structure highlighted with **dark blue** lines.

The major advantages of fieldbus require that sensors and final elements have digital computing capabilities. With computing at key elements in the control loop, much more information is available and can be provided for improved control. To take advantage of much of this information, we must broaden our view of the control loop, which traditionally involves one-way communication from sensor to controller to value. Now, we seek advantages from two-way communication and calculations at all loop elements. A few examples are given in Table 4.3.1.

Table 4.3.1 Typical communication for analog and digital transmission.

Loop elements involved	**Traditional, analog**	**Enhanced, digital fieldbus**
Sensor to controller	Signal representing the measured value sent to the controller	To controller ⑤ Measured value ⑤ Diagnostic from sensor To sensor ⑤ Configuration of sensors (e.g., zero and span values) Calculations at sensor

		⑤ Filtering measurement ⑤ Linearization ⑤ Correction for process environment (e.g., orifice for fluid temperature and pressure) which can require the use of several sensors
Controller to valve	Output of controller calculation sent to the valve (i/p converter)	To valve (to the i/p converter) ⑤ Output of controller ⑤ Configuration of valve (max/min openings, characteristic, etc.) To controller ⑤ position of stem position of valve ⑤ diagnostic from valve Calculations at valve ⑤ Modification of relationship between control signal and stem position to modify characteristic

In the traditional analog system, the sensor and valve are passive elements and all decision-making ability resides in the controller. In the digital system, key loop elements send and receive information and perform calculations in real time.

Thus, the fieldbus includes a change from a "controller-centric" distributed digital control system (DCS) design to Field Control System (FCS), in which all key components are actively involved in computation and data storage.

Some of the more important features of elements in a fieldbus system are introduced in the following.

1. **Configuration** - A large effort is required to configure (specify parameters like sensor range and valve characteristic) and verify data for elements of the loop. With Fieldbus, configuration can be prepared prior to plant construction and can be loaded and checked quickly. The savings in time and personnel costs can be substantial.
2. **Calculations** - Many calculations can be performed by the local processors to improve the performance of the elements.
   - ⑤ Sensor nonlinearities can be corrected, e.g., thermocouple conversions from millivolt to temperature.
   - ⑤ Several sensors can be combined to determine a more accurate value of a variable, e.g., density correction for a flow sensor.
   - ⑤ A desired inherent valve characteristic can be programmed into a valve.
3. **Multidrop** - The fieldbus can connect many elements using the same cable, rather than using individual cables for each signal as required by analog transmission. Again, ***saving can be substantial.***
4. **Two-way communication** - Any element can send and receive information, and any element can communicate with any other element on the fieldbus.

The distributed computing available in fieldbus makes possible the distribution of the controller calculations. For example, the element performing the controller (e.g., PID) calculation could be physically located at the sensor or valve. However, most plants desire control information to be available at a centralized location, the control room; therefore, the controllers are usually located in this control room.

In fieldbus designs, all elements (sensor, controller and final element) exchange information via digital transmission. We desire to purchase the best elements available from different suppliers.

Therefore, international standards are essential to ensure equipment from different suppliers will function in a network; this is termed interoperability.

Industry began to develop these standards in 1985, initial fieldbus systems were placed in operation in the 1990's, and standards and systems continue to evolve.

Comparison of Transmission Technologies

Electronic analog transmission has been the standard for several decades. As a motivation for changing, we require potential improvements for the digital transmission and smart instrument technology, and potential advantages for digital systems exist in performance and cost. A summary of some key advantages for each technology is given in Table 4.4.1.

Table 4.4.1. Major advantages of analog and digital signal transmission.

Technology	Advantages
Standard analog transmission	• Lower level of technology requires less skill to install and maintain • Lower impact on plant operation of a single cable failure • Lower installed cost for very small systems
Fieldbus transmission with "smart" sensors and valves	• Reduced cost for installation reduces cost and can shorten total project time • Sensor and valve diagnostics result in - reduced routine maintenance - faster trouble shooting - solution of incipient failures before they adversely affect the process • Higher accuracy for some sensors that use multiple measurements and non-linear calculations

Some recent provides experience on the savings for fieldbus over standard analog equipment. Cost reductions for fieldbus equipment were reported to be (Baltus, 2004),

- Wiring - 50%
- Commissioning (checkout and calibration) - 90%
- Space in the control house for instrumentation - 85%
- Maintenace - 50%

Cost advantages have been reported for projects involving many instruments. For example, the instrumentation cost for an acetic acid plant was reduced 31% by using fieldbus technology rather than conventional analog technology (ARC, 2005). It is important to recognize that while the equipment cost was higher for fieldbus, substantial savings were realized in cabling, wiring, calibration and programming.

Instrumentation Safety (Preventing Fire and Explosion)

Naturally, we must safely accomplish measurement, control calculations, and process modulation through adjusting the final element. Control systems contribute to safe process operation through basic control design, valve failure positions, alarms, safety interlock systems, and pressure relief systems (e.g., Marlin, 2000; AIChE, 1993; Lees, 1996). This section addresses one important hazardous condition, fire and explosion, that is affected by the design and implementation of control and transmission equipment. The material in this section is applicable to a wide range of processes and industries using either analog or digital transmission.

The information presented here provides an introduction to safety through the use of proper control equipment. This section gives a simplified discussion that is not adequate for engineering practice. The reader is cautioned to

- Refer to up-to-date safety specifications for control equipment,
- Ensure that the appropriate regulations are used for the location where the equipment will be installed, and
- Engage an experienced, registered engineer to review all designs.

All control equipment outside of a protected control room is in an environment with air and possibly, combustible materials; hydrocarbons, dust, or other materials. Note that these combustibles might not normally be present, but they are present in the process (e.g., within vessels and pipes) and could be in proximity to control equipment during unusual situations. The electrical power provided for the instrument introduces the third of the three components required for combustion or explosion, as shown in Figure 5.1. Naturally, combustion and explosion must be prevented, and two commonly employed approaches to prevent hazards are summarized in this section.

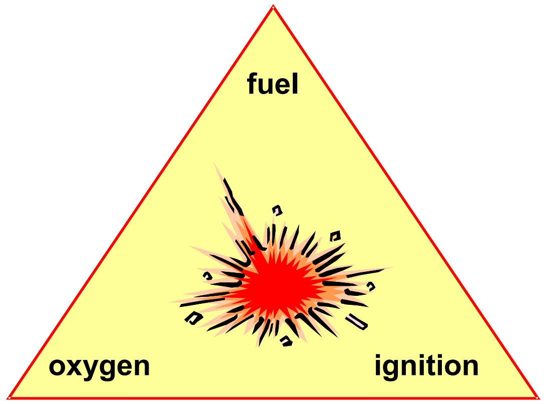


Figure 5.1. Triangle showing the three key elements leading to fire and explosions.

Safety can be achieved by removing at least one of the elements in the environment around instrumentation. An additional safety measure could contain the effects of any fire or explosion in a small region, which would prevent it from propagating and creating a major hazard. An approach for achieving safety by influencing each approach is introduced in the following.

- **Fuel** - A controlled environment can be continuously purged with air or an inert to remove fuel.
- **Oxygen** - The environment around an instrument can be immersed in a liquid or granular solid that will prevent oxygen (and fuel) from being affected by the source of ignition.
- **Ignition** - The power source can be maintained below the critical value that could initiate fire or explosion.
- **Containment** - An instrument can be surrounded with an enclosure that can contain a fire or explosion within the small region, where it will extinguish quickly because of lack of fuel and oxygen. This approach is termed "explosionproofing" in the United States and Canada and "flameproofing" in Europe; note that the term "proof" here does not mean "no explosion or flame", it means the combustion is contained and will not propagate to other areas in the process.

Generally, a process has a centralized control building that has an environment free from combustibles. The computers performing control calculations, safety controllers, historical data storage and other higher-level computing are located in this building, as are operations personnel. Sensors and final elements are located at the process, which can have oxygen and fuel present. We note that the fuel should not be present in high concentrations, except within process vessels and pipes. Instrumentation must be designed and operated to be safe, and instrumentation located in areas where a fuel source is not normally present must be safe even during the occurrence of very infrequent fuel releases due to small leaks or spills.

Hazardous Area Classification and additional specifications

The proper instrumentation design and installation depends on the likelihood of fuel being present and the type of fuel that could be present. The engineer must select the area classification from several categories and ensure that the instrumentation is compatible with safe operation. The appropriate local regulatory agency defines the categories, and the instrumentation manufacturer defines the set of specifications appropriate for each equipment. In most countries, the instrumentation equipment must be tested by an independent agency, such as Factory Mutual or Underwriters Laboratory, to verify the specifications given by its manufacturer.

Hazardous Area

The hazardous area classifications differ from country to country; for example, the classifications are different between North America and Europe, although efforts are being made to make them consistent. The classifications presented here are for North America, although since the classifications are in a state of change, the practicing engineer should check with the relevant agency for up-to-date information. Then, references are given for comparisons between the North American and European standards. Area classifications for combustible vapors and dusts are given in Table 5.1 (Ode, 2000).

Table 5.1 Hazardous Zone categories

Area Designation	**Area Description**
Zone 0	Ignitable concentrations of flammable gases or vapors are present continuously or present for long periods of time. Examples include, ⑤ Interior of tanks ⑤ Locations near vents
Zone 1	There may be ignitable concentrations during normal operating conditions or concentrations exist frequently from repair or maintenance of the equipment. Examples include, ⑤ An area where the breakdown of equipment could lead to a release ⑤ Remember that pumps and compressors can have small leaks
Zone 2	There may be ignitable concentrations during temporary situations. Examples include, ⑤ Storage where hazardous materials are in containers. ⑤ Areas adjacent to Zone 1 with no hazards of its own ⑤ Ventilation could prevent the hazard, but it could fail during a leak

Combustible material specification

In addition to a general quantity and likelihood of hazardous materials, the specific material is important. To simplify classification, several groups shown in Table 5.2 have been defined (Ode, 2000).

Table 5.2 Groups of combustible materials

Material Group	Description
Group A	Contains acetylene
Group B	Contains hydrogen
Group C	Contains ethylene
Group E	Contains metal dust
Group F	Contains coal dust
Group G	Contains grain dust

A key difference between the groups is the amount of energy required to cause ignition. For the gases, the most restrictive is Group A (lowest energy for ignition) and least restrictive is Group C.

Temperature Specification

Additional specifications are given for other performance variables, such as the operating temperature; categories for the maximum temperature are given in Table 5.3 Ode, 2000).

Table 5.3 Maximum temperature categories

Category	Maximum temperature °C (with 40 °C as ambient)
T1	450
T2	300
T3	200
T4	135
T5	100
T6	85

Note that some categories have sub-categories.

The specifications just described apply to above ground manufacturing and address fire and explosions, and they do not apply to special conditions, such as the following.

- Highly oxygenated atmospheres (oxygen greater than 20 mole %)
- Pyrophoric materials
- Underground, mines
- Any other hazards, e.g., hygiene or toxicology in food and pharmaceuticals

The remainder of this section presents two of the most important approaches for achieving safe instrumentation in the process industries, intrinsic safety and explosion proofing.

Intrinsic safety

Intrinsic safety influences the potential source of ignition without affecting the other two key elements in the safety triangle in Figure 5.1.

Intrinsic Safety: "A technique that achieves safety by limiting the ignition energy and surface temperature that can arise in normal operation, or under certain foreseeable fault conditions, to levels that are insufficient to ignite an explosive atmosphere" (Bentley Nevada, 2006).

If safety is to be ensured by preventing sources of ignition, excessive power must be prevented for normal and foreseeable fault conditions. For example, low electrical power could be used during normal operation, but reliable safety must also ensure that an electrical fault, which would provide higher voltage or current, must not propagate to the areas in contact with the combustibles.

The concept is shown in Figure 5.2. Note that the intrinsic safety barriers, wiring and the field instrumentation in the process area must be designed and installed as an integrated system.

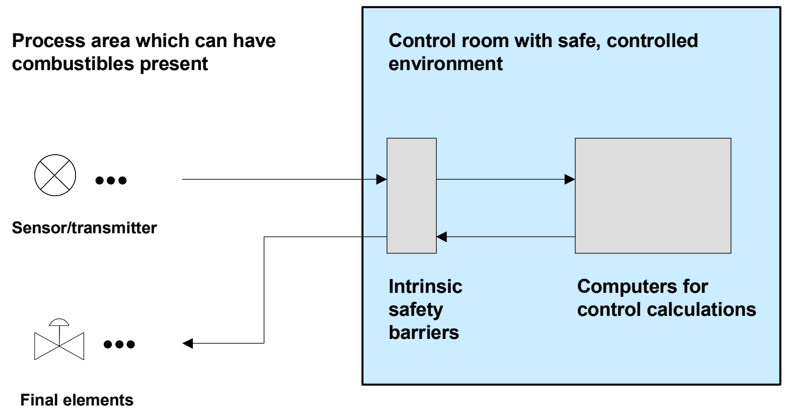


Figure 5.2. Concept of intrinsic safety in a process plant. Intrinsic safety includes the barriers, field instruments and wiring that must combine to prevent a source of ignition.

The fuel sources can vary widely in the process industries or even within different sections of a large plant. Therefore, several hazardous area classifications are defined that depend on the types of materials. The definitions and equipment performances are provided by national and international professional organizations and each country defines the requirements that must be satisfied within their jurisdiction. To satisfy these requirements, the equipment must be tested and certified by a body accepted by the relevant governmental agency. While the concepts and general goals for intrinsic safety are the same throughout the world, the numerous agencies can define different specifications, so that the engineer must be aware of and abide by the local regulations. In addition, insurance providers may define additional or more restrictive designs.

Explosion proofing

This approach reduces the possibility of a combustible mixture near the source of power combined with limits to the damage that could be caused by an explosion. Again, national and international regulations and standards are available.

Table 5.4 provides a quick comparison of intrinsic safety and explosion proofing, which is paraphrased from Honeywell (2006).

Table 5.4 Comparison of intrinsic safety and explosion proofing.

	Advantages	Disadvantages
Intrinsic Safety	⑤ Allows all three components of ignition triangle to coexist ⑤ No limit to power consumption	⑤ Enclosures can be bulky and costly ⑤ Any failure can compromise the entire system ⑤ Requires periodic inspection
Explosion Proofing	⑤ Safest ⑤ Inexpensive ⑤ Periodic inspection not required ⑤ Also prevents electrical hazards (shock) to workers	⑤ Applicable when less than 1 Watt required ⑤ Does not protect against ignition from other sources, e.g., lightening ⑤ Requires all elements of

		circuit to be intrinsically safe

Control Equipment Cost

Economics are always an issue in engineering practice. In a typical project, we incur expenses and acquire revenues over time, and we face the challenge of determining the best project decisions, where best means achieving the highest net profit. Fortunately, methods for economic analysis are readily available. These methods consider the time-value of money and provide appropriate measures of profitability, such as net present value (NPV). The methods for economic analysis are presented in many excellent textbooks, for example, Blank and Tarquin (2002).

Engineers are responsible for estimating the benefits and costs of a project. The benefits accrue from improved operation that improves product quality, increases reactor selectivity and separator recovery, increases production rates, reduces fuel consumption, and reduces undesirable effluents. The approaches and calculations for determining the benefits depend upon the specific project. General approaches and example data and calculations are available in, among others, Marlin et. al. (1987) and Shunta (1995).

This section presents some useful information for estimating the cost of control equipment. We must recognize the cost includes the following components.

- Purchase
- Transportation from supplier to user
- Installation and documentation
- Calibration
- Maintenance over the equipment lifetime

Some typical purchase costs are given in this section. Transportation cost clearly depends on the particular item and supplier. Installation includes the wiring, power, and programming any associated computing equipment. Calibration includes checking that the proper signal is connected to the desired computing element and ensuring that standard signals evoke the desired result, e.g., a temperature at the sensor provides the correct reading for display, alarm and control. Maintenance includes the cost of personnel and spare parts.

Typical purchase costs are given in Tables 6.1 to 6.3 at the end of this section. Most of this data has been provided by Liptak (2003; Liptak, 1999), who provides much valuable detail about each item. Proper cost estimation requires that the equipment matches the process requirements, which requires careful evaluation of equipment performance. Therefore, reference to Liptak (2003) and to suppliers' data is strongly recommended when performing cost estimations. However, the following typical data can be helpful for educational purposes and for quickly screening many potential projects.

In addition, we must recall that prices are a commercial decision negotiated between purchasers and suppliers. We expect that an order of many components will have a lower unit price than an order of one or a few components. The data below is typical for unit purchases.

Finally, engineers use "quick and dirty" approximate estimates when initially evaluating many projects. These methods are not very accurate, typically having uncertainty of ±30% or more. An example that is often needed is the cost of all instrumentation, including installation, for a plant construction project. Estimates are available (e.g., Perry's Handbook, 1997); however, the technology and costs have been changing rapidly, especially since the introduction of fieldbus digital communication. Therefore, caution must be used when applying correlations based on old technology, often from the 1960's.

Table 6.1 Sensors (conventional technology with transmitter, additional cost for "smart" features to be compatible with fieldbus technology)

Process variable	**Cost (US$ in 2003)**	**Comments**
Flow - orifice	500-3500	Flange connections, 2-12 in pipe
Flow - pitot and similar	1000-2000	Calibration costs extra
Flow - mass	1500-7000	1 in. pipe, cost depends strongly on sensor technology
Flow - positive displacement	3000-5000	1500 SCMH
Flow - turbine	3000	2-3 in. pipe, cost depends strongly on pipe size
Flow - venture/nozzle	500-1000	6 in. pipe, costs vary depending on sensor type and materials of construction
Temperature - thermocouple	200	Cost includes thermal well. With transmitter could cost up to $2000
Temperature - RTD	100-250	Cost includes thermal well. With transmitter could cost up to $2000
Temperature - thermister	See RTD	
Temperature - optical pyrometer	500-5500	Thermal imaging much more expensive
Temperature - bimetalic	65	For local display only
Pressure - bourdon	300	Local indication
Pressure - electronic	1000-4000	Many technologies (See Liptak, 2003)
Level - pressure difference	1500	Local indicators few hundred dollars
Level - float	2000-5000	Switch or local indicator lower cost
Level - displacement	2500	
Level - Laser	4000-6000	
Level - Radar	1500-5000	
Level - Ultransonic	650-2500	
Analyzer - sampling system	3500-7000	Single sample stream
Analyzer - installation	--	Varies depending upon the location, safety requirements, and analyzer technology
Analyzer	--	Must determine the cost for each analyzer type individually

Table 6.2 Controllers

Controller	**Cost (US$ in 2003)**	**Comments**
Temperature - regulators	400-1000	

Pressure - regulators	150-3000	Depends on pipe size and technology
Flow - regulator	250-1750	
Controller, electronic or digital	500-6000	Depends on flexibility in algorithms and number of controllers in single digital controller
Controller - pneumatic	1000-2500	
Distributed Digital Control System	--	See Liptak (1999) for a sample cost estimate for an integrated system

Table 6.3 Final elements

Final Element	Cost * (US$ in 2003)	Comments
Actuator	--	Cost included in valve cost
Ball valve body	2000	4 in piping
Butterfly body	2000	″
Globe valve body	3000	″
Diaphragm valve body	300-600	″
Accessories - positioner	600	″
Accessories - handwheel	500	Maximum cost
Accessories - limit switch indicator	50-150	

⑤ Note that all valve costs depend on the pipe size, materials of construction, etc. See Liptak (1999) and other resources for correlations of cost vs. pipe size and materials of construction.

Process Drawings

Engineers document their work using many complementary methods. Certainly, written documentation is important. However, drawings play an equally important place in documentation because of the complexity of the systems being documented and the precise and easily read nature of process drawings. This section provides a brief explanation of the major categories of drawings and WWW links for further information.

The major categories of drawings are introduced in the following.

⑤ ⑤ Block Flow

This drawing shows only the major units and process flows. The general goal is to provide an overview of the process to build understanding. An entire plant can be shown in a single drawing. Typically, each unit is shown as a rectangle (block), and the blocks are connected by solid lines with the flow direction indicated with arrows. No special symbols or guidelines are used in developing these drawings.

⑤ ⑤ Process Flow Diagram (PFD)

This drawing shows all major equipment and process flows in a single drawing. Symbols and identifications (e.g., T-201) are used to represent unit operations, and each stream is designated with a number. The stream properties are given in associated tables, but utility flow rates (e.g., air, steam, fuel, etc.) are typically not given.

In some drawings, a few basic control loops are provided to indicate how process flows and other key variables are maintained at desired values.

The drawing is not to scale.

⑤ ⑤ **Piping and Instrumentation Drawing (P&ID)**

These drawings give details on all piping, including valves (automated and manual), by-pass lines, pipe sizes, sample points, etc. In addition, all instrumentation is shown. A moderate level of mechanical detail is provided for process equipment, so that the piping and instrumentation can be precisely documented.

International symbol standards are used for piping, equipment and instruments (ISA, 1992).

Many pages of drawings are required for a single unit. The drawings are not to scale.

⑤ ⑤ **Equipment Mechanical Drawings**

Each equipment (e.g., drum, fired heater, etc.) is constructed to the specifications in the Equipment Mechanical Drawings and associated text explanations.

⑤ ⑤ **Three-dimensional Layout**

Equipment must be located so that they do not interfere with each other and so that space is available for people to travel through the process and perform tasks, such as maintenance. To ensure the layout is adequate, a three-dimensional representation is required. In the past, physical models were constructed to scale; however, a 3-D graphical representation is the standard technique used today.

While these general categories are used widely, each organization applies its own modifications. Therefore, every set of drawings should be accompanied by a key that defines the use of symbols and other drawing standards.

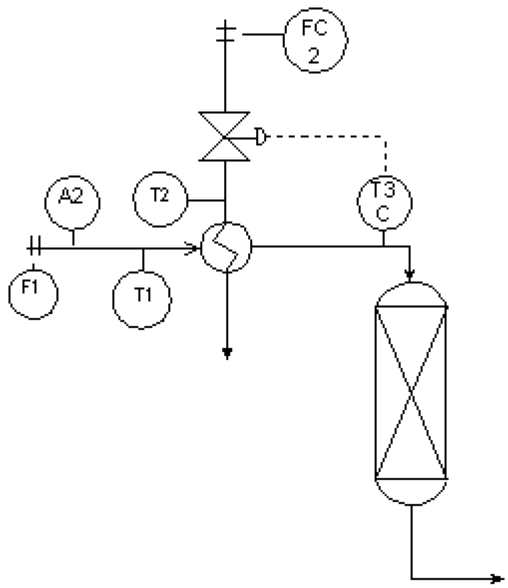
Many other drawings are used to document special issues. Examples are given in the following.

⑤ ⑤ Details of piping, sampling, etc.
⑤ ⑤ Loop drawings of connections between a sensor and valve in each control loop
⑤ ⑤ Logic diagrams for safety and other discrete control systems
⑤ ⑤ Plot plans of the entire site

In addition, documentation is required for cost estimation for the purchase, construction and start up of the process. This information is usually included in tables; some typical contents are pump/motor power, vessel size, piping diameter and lengths, pressures, temperatures, and materials of construction. Also, written documentation is required to purchase every one of the thousands and thousands of items. For example, a specification sheet is required for every sensor, transmitter, and valve.

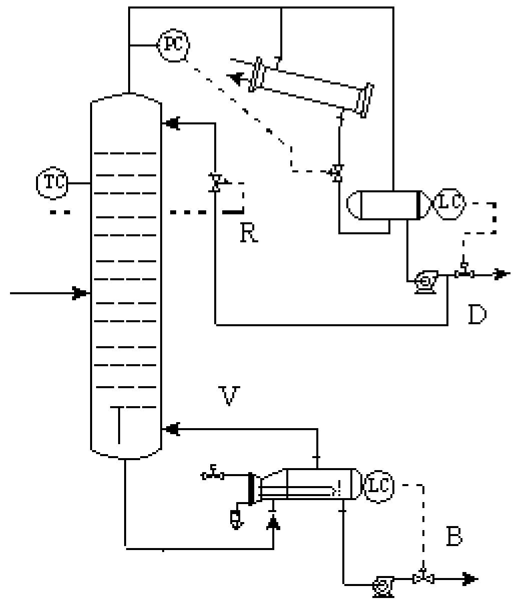
Solved Examples

Example 1) Temperature measurement before a chemical reactor: The feed temperature, T_3, to an isothermal chemical reactor should be controlled very accurately in the range of 400K. The product quality is measured only once every shift by laboratory analysis. The operator adjusts the set point of the feed temperature controller to achieve the desired product quality. What temperature sensor do you recommend?



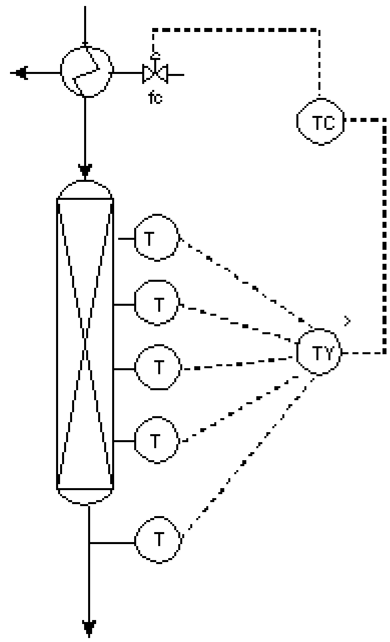
Solution:
Here, high accuracy is required in the range of 400K. Since accuracy is required, a thermocouple is not recommended. Since the temperature range is outside the region for a thermistor, **an RTD sensor is recommended**.

Example 2) Distillation tray temperature control: You have decided to use a tray temperature measurement in place of an analyzer for distillate composition control. This approach is referred to as inferential control (see Marlin, 2000, Chapter 17) and is used often to achieve reasonable control with low cost equipment. You would like to provide another measurement on the same tray to validate the sensor used for control. How would you do this?



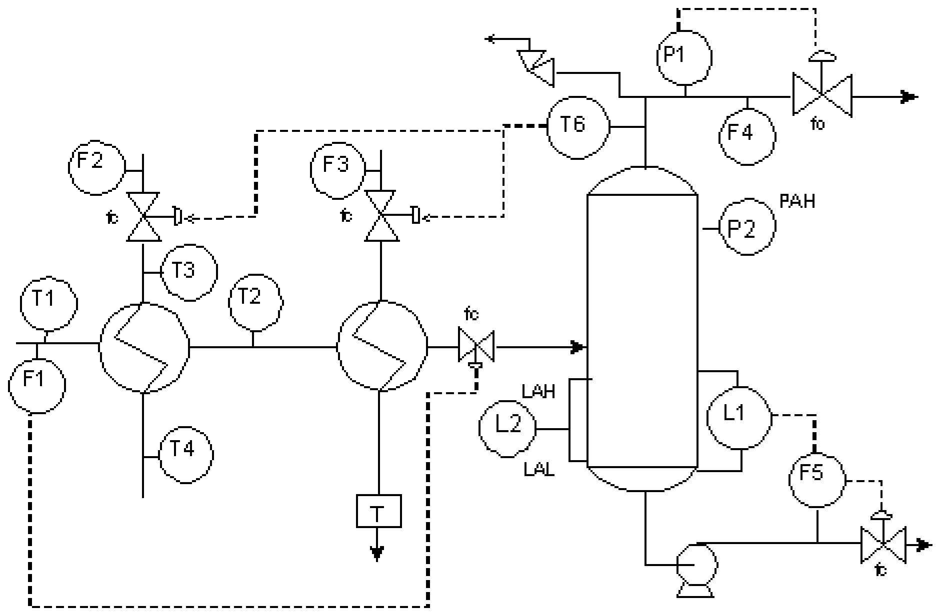
Solution:
Recall that the temperature sensor is protected from the process environment by a thermowell. Since we generally try to reduce the number of "holes" in a pressure vessel, we will place a second thermocouple in the same thermowell. This will provide a check on the temperature for most possible faults, such as a wire break. Clearly, both sensors will respond in the same manner to a fault like a buildup of material on the thermowell that slows the response of the sensors. This type of fault is not very likely in a distillation tower. This fault could occur in a chemical reactor, where coke can build up over time.

Example 3) Temperature measurement in a packed bed reactor: A highly exothermic chemical reaction is taking place in an adiabatic, catalytic packed bed reactor. Where would you place the temperature sensor to ensure that the maximum temperature is not exceeded?



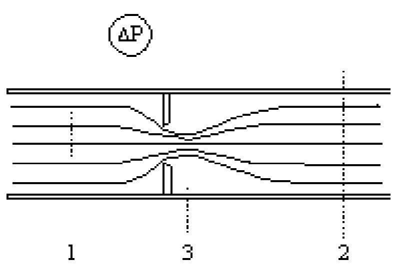
Solution:
This would be a simple problem if the flow through the reactor were plug flow; then, a single sensor at the outlet would provide sufficient information. However, the flow is not likely to closely approximate ideal, plug flow, so sensors should be placed throughout the bed. The details vary with the reactor size, catalyst activity and thermal properties, but typically, these reactors have many thermowells, each with several thermocouples measuring temperatures at different points down the length of the reactor. An important feature of the feedback control system would be to monitor all temperatures and control the **highest** to a set point.

Example 4) Temperature measurement:
You would like to measure a temperature in a flash separator, T_6. Great accuracy is not desired, because we plan to install an onstream analyzer. The stream pressure is 10 MPa, and the temperature range is 273-373 K. What sensor would you select?



Solution:
Since high accuracy is not required, a thermocouple is recommended. The pressure has no influence on the selection, and the thermocouple recommended in Table 1 is Type J for this temperature range.

Example 5) Flow measurement for gas with changing composition: You want to measure the flow rate of a hydrocarbon stream. Great accuracy is not required; the accuracy typically achieved with an orifice meter (±3-5%) is acceptable. Because of changes to upstream operation, the composition of the stream can change within the limits shown in the data below; however the pressure does not vary significantly. What sensor do you recommend?



	Base Case	Modified Case
Ethane	0 mole%	20 mole%
Methane	100 mole%	80 mole%

Solution:
The standard orifice meter measures only DP = P_1- P_3 and assumes the coefficient of resistance and the density are constant, i.e., $F_{sensor} = K_v\,(DP/r_0)^{0.5}$, with r_0 the density at the design or base case. The error due to the assumption can be evaluated by comparing the

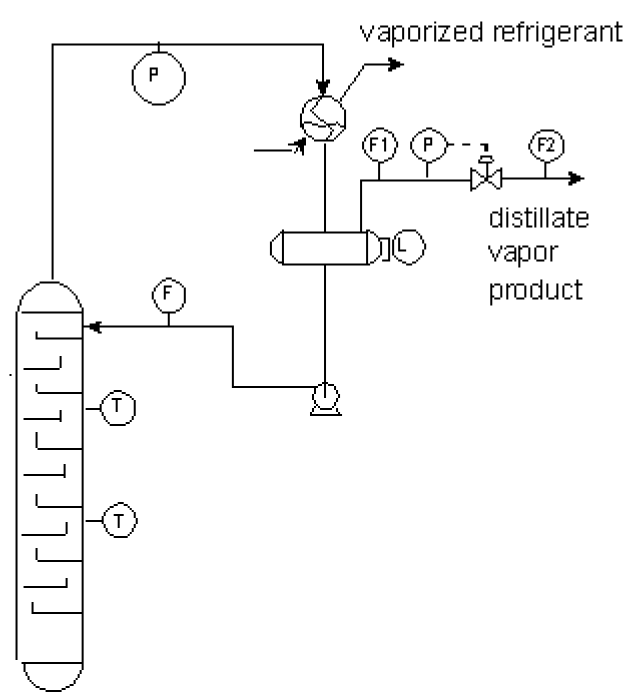
square root of the densities at the design point and the maximum deviation in molecular weight.

$$F_{actual} = K_v\sqrt{\frac{\Delta P}{\rho}} = K_v\sqrt{\frac{\Delta P}{\rho_0}}\sqrt{\frac{\rho_0}{\rho}} = K_v\sqrt{\frac{\Delta P}{\rho_0}}\sqrt{\frac{16}{18.8}} = (0.92)K_v\sqrt{\frac{\Delta P}{\rho_0}}$$

The error due to the change in density will be a bias of -8 percent, which would be in addition to other inaccuracies associated with an orifice meter. The actual volumetric flow rate would be less than recorded by a sensor assuming constant density. If the flow meter were the basis for purchasing the stream, you would be paying 8 percent too much! Where accuracy is needed, compensation should be applied by measuring the molecular weight of the gas and correcting as shown in the equation above.

Where the molecular weight of the gas changes significantly, density correction should be considered for head meters.

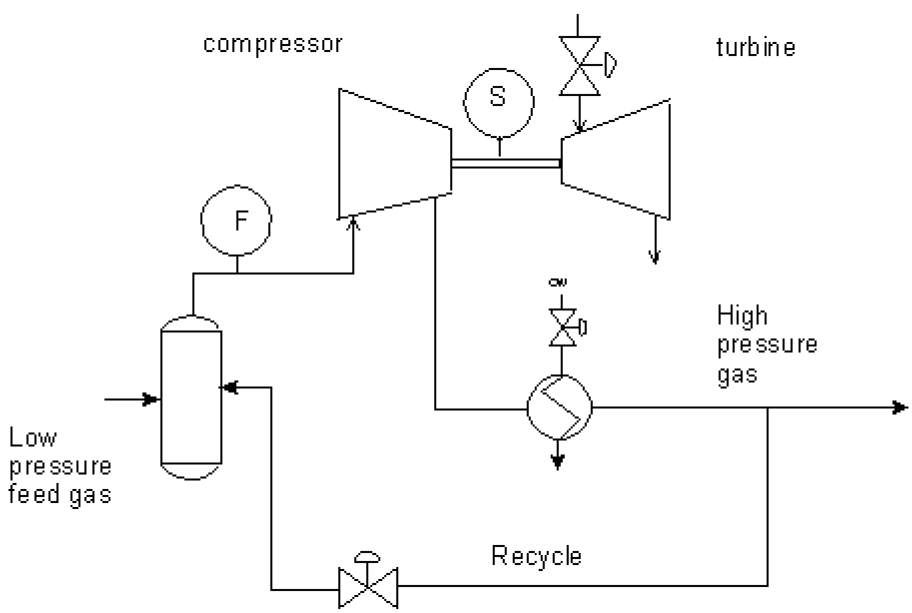
Example 6) Effect of pressure on a gas flow sensor: You wish to measure the vapor product from a distillation column. You have ascertained that an orifice sensor is a good choice. Decide the proper location for the sensor, F1 or F2.



Solution:
The two likely choices for measuring the gas stream are 1) immediately after the drum before the pressure control valve and 2) after the control valve. The key factor is accuracy; which location more closely satisfies the assumptions associated with the standard orifice sensor? Since the standard orifice sensor assumes constant density, you should select the location that has the most constant ***pressure***. The pressure in the overhead circuit is controlled, while the pressure downstream from the valve will vary with the flow rate. Therefore, the sensor before the control valve, F1, is chosen.

The best location for a head flow meter measuring a vapour flow rate has a small variation in absolute pressure.

Example 7) Pressure drop in measuring gas flows:
The flow of gas through a compressor is a very important variable. It is one important factor for the amount of energy required. In addition, a minimum flow rate is required to prevent unstable flow and mechanical damage to the compressor. What sensor would you recommend to measure flow at the suction to a compressor?

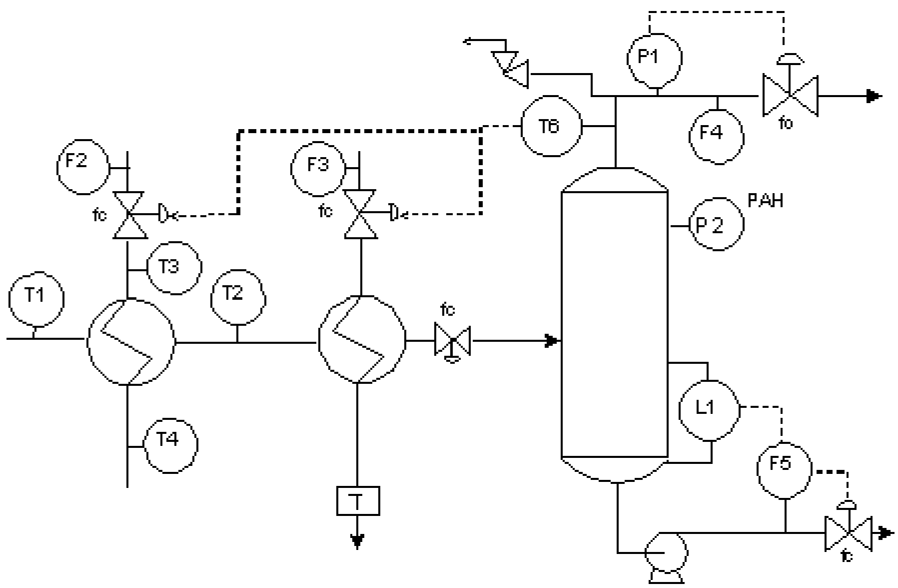


Solution:
The work required by the compressor depends on several factors, including pressure rise. To achieve the desired (low) pressure in the process upstream of the compressor, the suction pressure must be lower to account for the non-recoverable pressure loss due to the flow sensor. Thus, the pressure loss requires additional work to achieve the desired inlet

and outlet pressures. For this reason, a sensor with a very small pressure drop is selected. Usually, this would be an annubar or pitot tube.

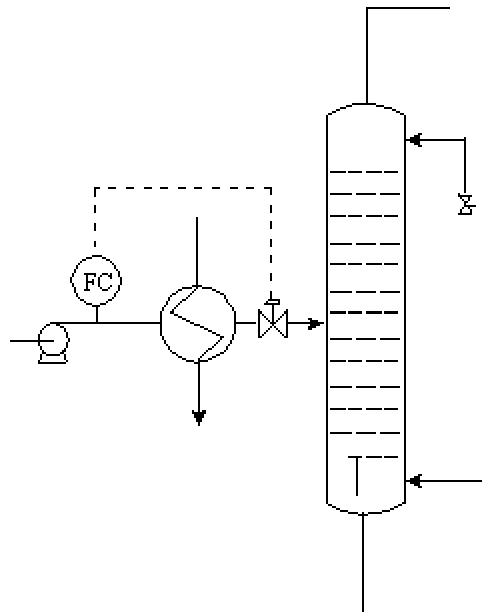
When compression costs are high, a flow sensor with a low (non-recoverable) pressure drop is recommended.

Example 8) Measuring a highly variable flow rate: We want to measure the vapor flow rate, F_4. The vapor flow rate from a flash drum varies over a large range because of changes in the upstream operation. The variation in total flow rate is about 20-100% of its maximum during *normal operation*; the composition does not change appreciably. You want to measure the flow rate with moderate accuracy, say ± 5% of its true value during normal operation; you do not need to measure the stream accurately during startup or shutdown. Decide which sensor to use.



Solution:
Let us discuss orifice meter technology first since it is inexpensive and very high accuracy is not required. The 5:1 range of variation is too great for accurate measurement using one orifice sensor. Therefore, you could install two sensors on the same pipe, one with a small range (0-35%) and one with a large range (0-100%). When the flow is small, the sensor with the smaller range would provide acceptable accuracy, and when the flow is large, above 35%, the sensor with the larger range would provide acceptable accuracy. Both sensors could use the same orifice meter. Other meters can provide this range with good accuracy and a single sensor. Examples are a turbine meter and various types of mass flow meters. See the Section 2.2 for details.

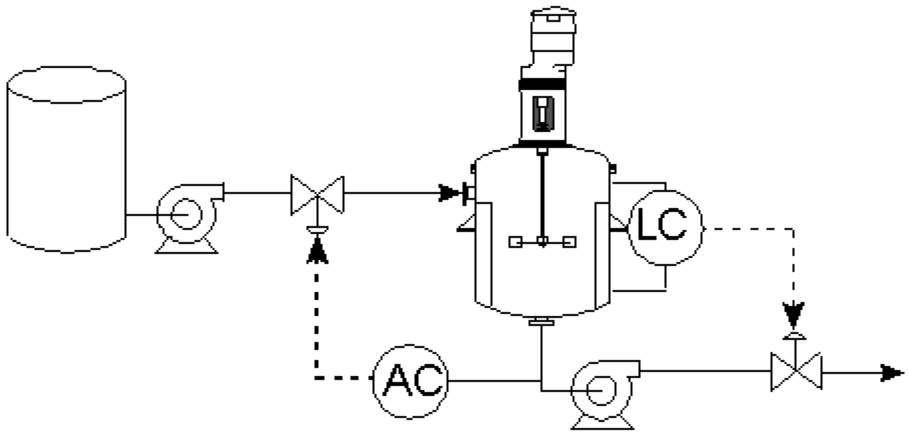
Example 9) Flashing flow: The feed to a distillation tower is preheated to recover energy from a process stream that is not hot enough to use for reboiling. You want to measure and control the feed flow rate to the distillation tower. Decide where to locate the sensor and valve for the feed flow controller.



Solution:
The feed is totally liquid when passing through the pump and is heated in the exchanger before entering the distillation tower. As you recall, the orifice sensor will not measure a two-phase flow; therefore, the sensor should be placed upstream of the heat exchanger. To maintain the highest pressure and prevent vaporization in the heat exchanger, the valve should be placed after the exchanger. The correct design is shown in the figure.

When flashing or cavitation is possible, a flow sensor should be located where the pressure is highest and the temperature the lowest.

Example 10) Valve characteristic for linear loop gain: The isothermal CSTR reactor with constant volume has its effluent concentration of reactant controlled by adjusting the feed flow rate. The reaction is first order. Also, the composition controller is a PI algorithm, and the level controller is a tightly tuned PI. Determine the valve characteristic.



Solution:
The steady-state model for the system is easily derived from a component material balance.

$$\frac{dC_A}{dt} = FC_{A0} - FC_A - VkC_A = 0$$

This can be rearranged to express the concentration as a function of the feed flow.

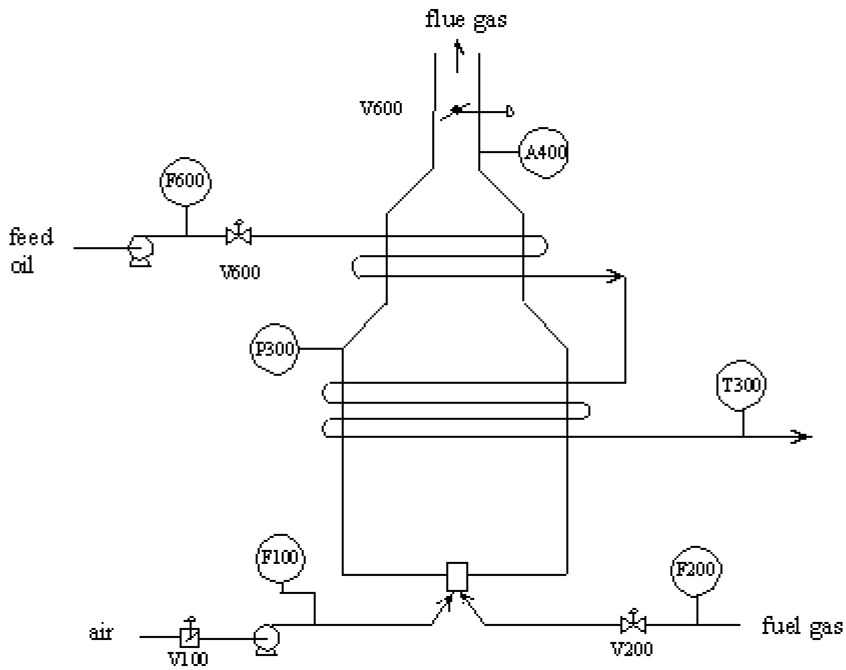
$$C_A = C_{A0}\frac{F}{F + Vk}$$

The steady-state gain is given by

$$\frac{dC_A}{dF} = C_{A0}\left(\frac{Vk}{(F + Vk)^2}\right)$$

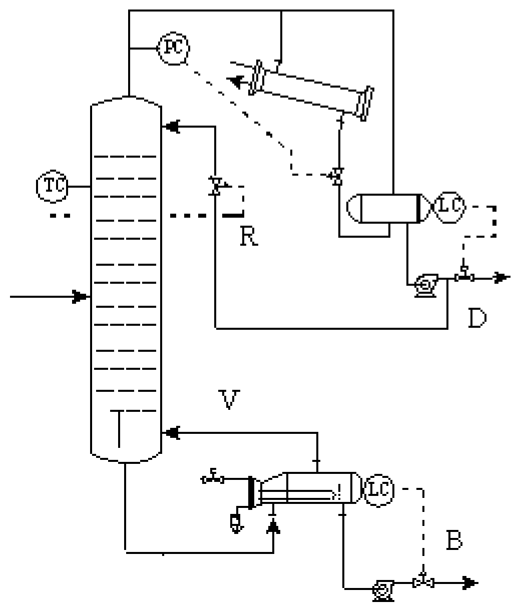
The gain always is positive. At low flow rates, the gain has its highest value, and as the flow increases (the control valve opens) the gain decreases in magnitude. Therefore, the proper installed valve characteristic would have a low gain at small valve openings and a large gain at large valve openings. This is generally the shape of an equal percentage characteristic. To finalize the design, we would have to substitute the numerical values for the parameters, and also, we would have to determine how much the supply pressure changes with valve opening.

Example 11) Low pressure drop valve: The flue gas flow rate leaving a fired heater is adjusted to control the pressure in the fired heater. Select a valve for this application.



Solution:
Generally, the volumetric flow rate of flue gas is high because of the large amount of nitrogen and the high temperature of the gas. Also, the fired heater is operated near atmospheric pressure. Therefore, a valve with a very low pressure drop is required. The standard choice is a butterfly valve, also called a stack damper. Note that a low pressure drop valve is also used when the cost of pumping or compression is very high.

Example 12) Location of flow valve around a pump: The liquid from the bottom accumulator of a distillation tower is pumped to a downstream unit. Decide where the flow control valve should be located.



Solution:
The valve is required to provide a variable resistance for flow control. At least conceptually, the valve could be located before or after the pump. However, the liquid leaving the tower (or reboiler) is at its **bubble point**, so that any significant pressure drop in the valve located before the pump will lead to vaporization in the valve and partial vapor flow through the pump, leading to cavitation and damage. Therefore, the valve is located at the outlet of the pump, where the pressure is much higher and cavitation does not occur.

Control valves are located at the outlet of pumps, not at the inlet.

Terminology

Experience has shown that considerable misunderstanding can occur when engineers discuss the performance of process instrumentation. Clearly, this situation is likely to impede education; in addition, it can cause serious errors in specifying and purchasing instrumentation to satisfy requirements. Purchasers and suppliers must share an unequivocal understanding of the performance specifications of equipment, including instrumentation. Thus, professional organizations have prepared standard definitions of key terms (e.g., ISA, 1979); practicing engineers are well advised to use these standards.

A few of the most frequently used terms are presented here.

***Accuracy*:** Degree of conformance of a value to a recognized, accepted standard value. Accuracy is expressed as the maximum positive and negative deviation from the standard for specific conditions, usually expressed as the inaccuracy as a percent of the value, instrument range, or full-scale value. It includes causes of inaccuracy, including linearity, repeatability and hysteresis.

***Dead Band* :** The range through which an input can be varied, upon reversal of direction, without causing an effect in the output signal.

***Drift* :** An undesired change in output over a period of time that is unrelated to the input and operating conditions.

Hysteresis: The property that the output depends on the history of the input and current direction of change.

***Linearity* :** The closeness of the calibration curve to a straight line. It is expressed as the maximum deviation of the calibration curve and the specified straight-line characteristic.

***Range* :** The region within which a value is measured, received or transmitted, expressed as lower and upper range values.

Repeatability: The closeness of agreement among consecutive measurements of the output for the same value of the input under the same operating conditions and approaching from the same direction. It is usually reported as non-repeatability in percent of span and does not include hysteresis.

***Reproducibility*:** The closeness of the output reading for the same value of input over a period of time approaching in both directions. It is usually reported as non-reproducibility as a percent of span and includes hysteresis, drift, repeatability and dead band.

***Response Time* :** Time required for an output to reach a specified percentage of its final value as a result of a step change in input.

***Span* : The difference between the upper and lower limits of range.**